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Final Staff Assessment
Part 2

CALIFORNIA
ENERGY
COMMISSION

SALTON SEA GEOTHERMAL UNIT #6 POWER PROJECT

Application For Certification (02-AFC-2)
Imperial County

STAFF REPORT

SEPTEMBER 2003
(02-AFC-2)

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Gray Davis, Governor

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CALIFORNIA ENERGY COMMISSION

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EXECUTIVE SUMMARY

By Robert Worl

The California Energy Commission staff has prepared this Final Staff Assessment (FSA) Part 2 for the Salton Sea Unit 6 geothermal power project. The FSA has been divided into two parts. Part 1was filed August 5, 2003 and included all areas except Air Quality and Alternatives. Part 2 includes Air Quality, Alternatives and an amended Public Health analysis.

On July 26, 2002, CE Obsidian Energy LLC (CEOE, project owner) filed an Application for Certification (AFC), for its proposed Salton Sea Unit 6 geothermal project (SSU6) with the California Energy Commission seeking approval to construct and operate a 185 megawatt (MW) geothermal steam-powered electric generating facility. The plant would be owned and operated by CEOE. The Energy Commission determined the application to be data adequate on September 25, 2002. This determination initiated staff's independent analysis of the proposed project.

The SSU6 and related facilities, including the electric transmission lines, and water supply pipeline are under the Energy Commission's jurisdiction. For geothermal power projects, the Energy Commission evaluates all aspects of the project but the licensing of the geothermal production and injection wells occurs through permitting by the Department of Conservation, Division of Oil Gas and Geothermal Resources (DOGGR), and the well pads and brine pipelines are permitted by Imperial County (Public Resources Code section 25120). Both agencies intend to use the Energy Commission's Decision as the CEQA document for their respective actions.

As a result of its analysis, Energy Commission staff developed conditions of certification that mitigate impacts of the project. Where impacts of the project may occur from facilities licensed by other agencies, staff developed conditions of certification that are recommended to those agencies for inclusion in their respective permits based upon this FSA.

This FSA is not the decision document for these proceedings nor does it contain findings of the Energy Commission related to environmental impacts or the project's compliance with local, state, and federal legal requirements. The FSA will serve as staff's testimony in evidentiary hearings to be held by the Committee of two Commissioners who are hearing this case. The Committee will hold evidentiary hearings and will consider the recommendations presented by staff, the project owner, all parties, government agencies, and the public prior to proposing its decision. The Energy Commission will make the final decision, including findings, after the Committee's publication of its proposed decision.

PROJECT LOCATION AND DESCRIPTION

The project site is located near the southeast shore of the Salton Sea, is within the unincorporated area of Imperial County, California, and is located approximately 6.1 miles northwest of Calipatria, on an 80-acre portion of a 160 acre agricultural parcel owned by CEOE. The parcel is bounded by McKendry Road on the north, Peterson Road on the south, Severe Road on the west and Boyle Road to the east. The site is approximately 1,000 feet from the southern end of the Sonny Bono Salton Sea National Wildlife Refuge. Lying within the Salton Sea Known Geothermal Resource Area (KGRA), the project is within a two-mile radius of nine operating geothermal power projects. A more complete description of the project is contained in the **PROJECT DESCRIPTION** section of this FSA and includes figures depicting the regional setting, transmission line routes, wells and pads, brine pipelines, water pipeline and the proposed plant configuration.

The SSU6 would consist of a geothermal steam power plant, associated water supply, production and reinjection wells and pads, brine pipelines, two 161 kV transmission lines that would connect at two locations in the Imperial Irrigation District's (IID) transmission system, the L-Line (IID designates many of their transmission lines with letter designations) to the southwest, and the Midway substation to the east. A new switchyard, located approximately 12.5 miles from the project site on Bannister Road, would facilitate the L-Line interconnection. Approximately 31 miles of new single-circuit transmission lines would be constructed.

The SSU6 project has infrastructure elements unique to a geothermal project including a geothermal Resource Production Facility (RPF), geothermal-steam Power Generation Facility (PGF), production and injection wells and pads, above-ground brine pipelines, a brine-waste solids handling system, and unique emissions characteristics.

The SSU6 includes a high efficiency condensing steam turbine with a net plant output of 185 MW. Normally, the facility would be operated in a base load mode: 8,000 hours per year or more. This renewable energy project is designed to supply capacity and energy to California's electric market with over 85 percent of the plant output contracted to the IID for a 20 year period following project completion.

The SSU6 air emissions are quite different from those of a natural gas-fired plant. Except for drilling and ancillary equipment, NO_X, and SO_X are not emitted, but there will be emissions of ammonia and hydrogen sulfide (H_2S). Both ammonia and H_2S are non-compressible gasses contained in the geothermal brine. The ammonia emissions, though not a regulated emission, are of concern as an inhalable particulate matter 10-microns or less (PM_{10}) precursor. The project owner proposes to purchase PM_{10} emission credits at a greater than 1-to-1 ratio from agricultural burn cessation or other sources through the Imperial County Air Pollution Control District (ICAPCD). To control emissions and impacts of H_2S, the project owner proposes to install bio-oxidizers on the cooling towers of SSU6 and retrofit the cooling towers at an existing facility.

PUBLIC AND AGENCY COORDINATION

The Energy Commission's SSU6 Committee conducted an Informational Hearing and Site Visit on November 19, 2002. The Energy Commission also heard testimony regarding the sufficiency of the geothermal resources for support of the project through its projected 30-year life. The hearing provided a forum for the public to learn about the project, the Energy Commission's siting process, and to raise their questions and concerns about the proposed power plant. In addition, publicly noticed data response workshops were held on January 8 and 9, 2003 in Calipatria, and on February 27, 2003 in Sacramento. The Preliminary Staff Assessment was published April 14, 2003 with workshops held on May 14 and 15, 2003 in El Centro, and by phone on June 4, 2003.

Staff coordinated their review with the ICAPCD, the Imperial County Planning/Building Department, the U.S. Bureau of Land Management (BLM), U.S. Fish and Wildlife Service (USFWS), the U.S. Army Corps of Engineers (ACOE), the California Department of Conservation, Division of Oil, Gas, and Geothermal Resources (DOGGR), California Department of Toxic Substances Control, the California Department of Fish and Game (CDFG) and the Colorado River Basin Regional Water Quality Control Board (RWQCB

The Imperial County Planning/Building Department has agreed to use Energy Commission conditions of certification, monitoring protocols, and compliance field staff to the extent possible to avoid duplication of agency functions in the review and permitting of the SSU6, well pads and brine pipelines, and to assist in CEQA compliance for the project. DOGGR has indicated their intent to use the Energy Commission Decision as the environmental document for their well permitting actions.

The ACOE and the BLM have federal jurisdictional authority and must take certain actions to permit certain aspects of the project. ACOE has already completed their action permitting fill of a small portion of degraded wetland necessary for construction of a brine pipeline and is evaluating the proposed site of the Bannister Road switchyard to be constructed by IID. BLM must amend the California Desert Conservation Act (CDCA) Plan to allow a transmission line corridor across a portion of BLM land and has initiated that process.

In a letter dated September 9, 2003, the ACOE requested that USFWS continue the biological consultation under Section 7 of the Endangered Species Act which had begun with the BLM. ACOE is reviewing the entire project and has requested the Biological Opinion from the USFWS regarding potential impacts and proposed mitigation for threatened and endangered species within the project sphere of influence. USFWS has indicated that the Biological Opinion will be available October 24, 2003.

OUTREACH AND ENVIRONMENTAL JUSTICE

The Energy Commission Public Adviser’s Office has continued to solicit and support public input regarding the SSU6. A Spanish/English bilingual project description describing the project, explaining the process and providing contact information was prepared. Copies of the AFC were distributed to the El Centro and Calipatria libraries and, in addition to the project description flyers, posters were prepared announcing the project for those locations. Additionally, 1,400 bilingual project description flyers were distributed to homes through the Calipatria Unified School District. An additional 5,000 flyers were sent to the Imperial Valley Press for distribution. The Public Adviser also participated in the Informational Hearing and Site Visit in Calipatria on November 19, 2002, and at the Preliminary Staff Assessment Workshop held in El Centro on May 14 and 15, 2003. The Public Adviser continues to respond to requests for information from the public and provide referrals to staff.

Staff's environmental justice approach includes providing notice (in appropriate languages) to the public, including minority and/or low income communities, of the proposed project and opportunities for participation in public workshops. Analysis of potential environmental justice impacts includes assessing the minority population and low income economic status in an area within a 6-mile radius of the project.

Presentation and analysis of demographic and economic information is contained in the **SOCIOECONOMICS** section of Part 1 of the FSA. Staff has reviewed Census 2000 information that shows the minority population is greater than fifty percent within a six-mile radius of the proposed SSU6 Project and Census 2000 information that shows the low-income population is less than fifty percent within the same radius. The environmental justice analysis includes assessment of potential impacts in the following technical areas because an environmental justice population occurs within the 6-mile radius of the SSU6: air quality, public health, hazardous materials, land use, traffic, water resources, waste management, visual resources, noise, and transmission line safety and nuisance. Based on this analysis, staff for affected technical areas have identified no disproportionate impacts on the environmental justice population from the construction or operation of the project

CONCLUSIONS

With the exception of ammonia, the proposed conditions of certification insure that the project's public health and safety, and environmental impacts can be mitigated to levels of less than significance. And, with the exception of hydrogen sulfide during commissioning, the project would conform to all laws, ordinances, regulations and standards (LORS). The following is a brief discussion of these issues.

The project owner is planning to use H_2S offsets obtained from retrofitting the cooling towers of the nearby Leathers power plant with bio-oxidizer boxes similar to those planned for use on the project. The expectation is that H_2S reductions of at least 90 percent will be achieved through this application, providing the necessary offsets for the SSU6 project. Verification of this efficiency was completed and the results of emissions verification testing at the Leathers facility were transmitted to ICAPCD and the Energy Commission on August 14, 2003. To further reduce emissions, a polishing system will be employed at the SSU6 project using a solid bed H_2S removal scavenger system.

ICAPCD issued its Revised Final Determination of Compliance (FDOC) September 8, 2003. Staff has reviewed the revised FDOC as well as the proposed changes in modeling and mitigation strategies. Based on this review, we have determined that after applying available and feasible mitigation, significant unmitigated impacts from hydrogen sulfide and ammonia will remain. H_2S will likely exceed the California Ambient Air Quality Standard during approximately 5 hours over a 15 day commissioning period. Ammonia is of concern as a precursor for inhalable particulate matter (PM_{10}) in the Salton Sea air basin. Ammonia emissions will occur throughout the operational life of the SSU6. A complete discussion of the emissions and the current understanding of potential impacts is contained in the **AIR QUALITY** and **PUBLIC HEALTH** sections.

The **Public Health** analysis concludes, however, that even in the worst-case emissions scenario that there would be no significant long-term impact to the overall health of area residents.

The following table summarizes the technical areas analyzed in Part 1 and 2 of this FSA indicating levels of impact, LORS compliance and whether conditions of certification are recommended to other agencies for consideration.

ENVIRONMENTAL IMPACTS, LORS CONFORMANCE, AND CONDITIONS RECOMMENDED TO OTHER AGENCIES

Technical Discipline	Environmental/ System Impact	LORS Conformance	Conditions Recommended To Other Agencies
Air Quality	Yes	No	Yes
Biological Resources	Impacts mitigated	Yes	Yes
Cultural Resources	Impacts mitigated	Yes	Yes
Power Plant Efficiency	No	N/A	NA
Power Plant Reliability	No	N/A	NA
Facility Design	No	Yes	No
Geology/Paleontology	Impacts mitigated	Yes	Yes
Hazardous Materials	Impacts mitigated	Yes	No
Land Use	Impacts mitigated	Yes	No
Noise	Impacts mitigated	Yes	Yes
Public Health	Yes	No	No
Socioeconomics	Impacts mitigated	Yes	No
Traffic and Transportation	Impacts mitigated	Yes	No
Transmission Line Safety	No	Yes	No
Transmission System Engineering	Impacts mitigated	Yes	No
Visual Resources	Impacts mitigated	Yes	No
Waste Management	Impacts mitigated	Yes	No
Water and Soils	Impacts mitigated	Yes	Yes
Worker Safety	Impacts mitigated	Yes	No

RECOMMENDATIONS

If the Energy Commission determines that a proposed project would result in unmitigated significant adverse impacts to public health and safety, the environment, or the electric transmission system, the Commission must make findings of overriding considerations in order to certify the project. In particular, the Energy Commission must find that: (1) specific considerations make infeasible the mitigation measures or project alternatives identified in the proceeding; and (2) that the benefits of the project outweigh the unavoidable significant environmental effects that may be caused by the construction and operation of the facility (Cal. Code Regs., tit. 20, § 1755(d)).

Pursuant to item (1) above, staff has found significant Air Quality and Public Health impacts from H_2S emissions during initial commissioning and a significant air quality impact from the release of ammonia during the operation of the project. Steam venting which occurs at system checks and warm-up during commissioning, bypasses the gas reduction systems at times. Ammonia, also a non-compressible gas component that is retained in the recondensed steam, is released when that condensed water is used as makeup water in the cooling towers. No alternate source of makeup water is available, and no feasible chemical or mechanical means of ammonia reduction has been identified as feasible.

As described more fully in the Alternatives section, staff has also determined that none of the alternatives would allow the applicant to meet the objective of generating power from the Salton Sea geothermal resource. In addition, none of the alternative sites analyzed by staff appear to reduce the significant adverse impacts of the project. Therefore, none of the project alternatives are feasible.

Pursuant to item (2) above, Energy Commission staff concludes that the project's electric system and other benefits substantially outweigh the project’s significant air quality and public health impacts. According to the Energy Commission’s Energy and Natural Gas Report (staff draft, August 2003) the supply market 2006 and beyond is of concern, particularly for the 1-in-10 hot-summer scenario.

To prevent tight supplies from materializing in the year 2006 and beyond, the State of California has been working on modifications to the electricity market, pursuing upgrades in the transmission system (most notably Path 15 upgrades), developing energy conservation programs (e.g., the “Flex Your Power” campaign and the “20/20 Program”), and has entered into a series of long-term contracts. Energy predictions also rely upon development of new renewable facilities, partly in response to the Renewable Portfolio Standards established under SB 1078 (Sher, Statutes of 2002).

The SSU6 project is a small but critical part of the overall strategy to provide California with an adequate supply of electricity for economic growth and prosperity, stable electric prices, and a reliable electric system for the future (2006 and beyond).

In addition to the electric system benefits, the project would provide the following economic benefits:

- Approximately $100 million dollars will be spent locally, producing $7.75 million dollars in sales tax revenues and annual property taxes of $2.9 million dollars;
- Project employment includes 265 new construction jobs, with a one-month peak of 497, over a 26-month period;
- Project induced/indirect employment would add 104 jobs to the region;
- An estimated $30 million dollars would be expended on the construction payroll;
- Permanent operations would add 69 permanent jobs, 90 percent local hires;
- Operations payroll is expected to be $5.9 million dollars annually.

Additionally the SSU6, a renewable geothermal energy project, is consistent with the State Energy Action Plan that mandates increased reliance on renewable energy. It would add 185 MW of renewable power to the grid and diversity to the State's energy portfolio. SSU6 is financed and will likely be constructed immediately. The applicant has contracted 170 MW of the 185 MW output to IID for twenty years if the project is approved.

If the Energy Commission determines that a proposed project "does not conform with any applicable state, local, or regional standards, ordinances, or laws," it may not certify the project unless it "determines that such facility is required for public convenience and necessity and that there are not more prudent and feasible means of achieving such public convenience and necessity. In making the determination, the commission shall consider the entire record of the proceeding, including, but not limited to, the impacts of the facility on the environment, consumer benefits, and electric system reliability" (Public Resources Code Section 25525).

The project's failure to conform arises from the predicted concentrations of H_2S during a portion of the initial commissioning of the project. The H_2S will likely exceed the California Ambient Air Quality Standard during approximately 5 hours over a 15 day commissioning period. At the predicted levels, annoyance to persons visiting Rock Hill or working in the vicinity of the project is likely during those periods. Sensitive individuals may experience headache or nausea as a result of exposure to exceedances of H_2S. That is inconsistent with Health and Safety Code Section 41700, which prohibits emissions which would cause injury nuisance or annoyance to the public. No long term health effects are expected from such an exposure and the applicant will be required to give notice of the commissioning activities before they take place (Condition of Certification **AQ-1**). As noted in the **AIR QUALITY** analysis, the ammonia (NH_3) emissions are also deemed significant as a precursor for the formation of PM_{10}. No direct mitigation for the ammonia emissions is available, and other potential means of direct mitigation or reduction are not feasible.

The project will provide needed additional electric generation capacity to the grid and increase the diversity of California's energy supply as described above. The public convenience and necessity would be served by its approval. There are no other feasible means of providing renewable geothermal energy from the Salton Sea geothermal resource. Given the short duration of the nonconformance with Section

41700 and the substantial benefit to the electricity system, override of the nonconformance is appropriate.

Staff recommends that the Commission approve the Salton Sea Unit 6 Application for Certification, including staff's proposed conditions of certification, with overriding considerations for the environmental impacts and LORS non-conformance.

SALTON SEA UNIT 6 PROJECT
(02-AFC-2)
FINAL STAFF ASSESSMENT PART 2

ENVIRONMENTAL ASSESSMENT

AIR QUALITY

Testimony of Lisa Blewitt and William Walters

INTRODUCTION

This analysis evaluates the expected air quality impacts of the emissions of criteria air pollutants due to the proposed geothermal Resource Production Facility (RPF) merchant class geothermal-powered Power Generation Facility (PGF), and other systems associated with the Salton Sea Unit 6 (SSU6) Project. The SSU6 Project is to be located in the Imperial Valley, southeast of the Salton Sea, in an unincorporated area of Imperial County, as proposed by CE Obsidian Energy LLC. Criteria air pollutants are those for which a federal or state ambient air quality standard has been established to protect public health. They include ozone (O_3), nitrogen dioxide (NO_2), carbon monoxide (CO), sulfur dioxide (SO_2), volatile organic compounds (VOC), hydrogen sulfide (H_2S), and particulate matter less than 10 microns in diameter (PM_{10}).

In carrying out the analysis, the California Energy Commission staff evaluated the following major points:

- whether the proposed Salton Sea Unit 6 Project is likely to conform with applicable Federal, State and Imperial County Air Pollution Control District (ICAPCD or District or APCD) air quality laws, ordinances, regulations and standards (LORS), as required by Title 20, California Code of Regulations, section 1742.5 (b);
- whether the Salton Sea Unit 6 Project is likely to cause significant air quality impacts, including new violations of ambient air quality standards or contributions to existing violations of those standards, as required by Title 20, California Code of Regulations, section 1742 (b); and
- whether the mitigation proposed for the Salton Sea Unit 6 Project is adequate to lessen the potential impacts to a level of insignificance, as required by Title 20, California Code of Regulations, section 1744 (b).

LAWS, ORDINANCES, REGULATIONS AND STANDARDS

FEDERAL

The federal Clean Air Act requires any new major stationary sources of air pollution and any major modifications to existing major stationary sources to obtain a construction permit before commencing construction. This process is known as New Source Review (NSR). Its requirements differ depending on the attainment status of the area where the major facility is to be located. Prevention of Significant Deterioration (PSD) requirements apply in areas that are in attainment of the national ambient air quality standards (NAAQS). The non-attainment area NSR requirements apply to areas that have not been able to demonstrate compliance with the NAAQS. The entire program, including both PSD and non-attainment NSR permit reviews, is referred to as the federal NSR program.

The U.S. Environmental Protection Agency (USEPA) has reviewed and approved the ICAPCD's regulations and has delegated to the District the implementation of the federal non-attainment NSR, Title IV, and Title V programs. The ICAPCD implements these programs through its own rules and regulations, which are, at a minimum, as stringent as the federal regulations. The USEPA has not delegated the PSD permitting program to ICAPCD; however, the SSU6 Project emissions are below the regulatory thresholds that trigger the need for a PSD permit.

Title V of the federal Clean Air Act requires states to implement and administer an operating permit program to ensure that large sources operate in compliance with the requirements included in the Code of Federal Regulations, Title 40, Part 70. A Title V permit contains all of the requirements specified in different air quality regulations that affect an individual project. The Title V program is administered by ICAPCD under Regulation IX (Rule 900). The project emissions, as shown in Air Quality Table 15, are below the regulatory thresholds (100 tons/yr for any criteria pollutant and 10 tons/year for any hazardous air pollutant (HAP or 25 tons for all HAPs combined), and the project is not defined as one of the source categories (specified in District Rule 900 C.1) that trigger the need for a Title V permit.

Enforcement of the federal New Source Performance Standards (NSPS) has been delegated to the ICAPCD and the corresponding regulations are incorporated into the District's Regulation XI (Rule 1101). The NSPS are a series of regulations that are specific to new emission sources and industries and these regulations can specify emission limits and emission monitoring requirements. For power plants, this regulation applies to those plants with gas turbines and steam generating units. Since the SSU6 Project is a geothermal plant, this regulation does not apply.

The USEPA has delegated its non-attainment New Source Review (NSR) permitting authority to the ICAPCD. This delegation is only done for air districts that are able to demonstrate to the satisfaction of USEPA that their regulatory programs are at least as stringent as the federal PSD and non-attainment NSR programs. The ICAPCD will issue a Determination of Compliance, which is equivalent to an Authority to Construct (ATC), and will only issue a Permit to Operate after this project secures a license from the California Energy Commission. This permit will be equivalent to a federal non-attainment NSR permit.

Title IV of the federal Clean Air Act provides for the issuance of acid rain permits and requires subject facilities to obtain emission allowances for SO_x emissions. The Title IV program is administered by ICAPCD under Regulation IX (Rule 901). The project is not a fossil fuel fired generating unit as defined by 40 CFR Part 72 and is therefore not subject to Title IV regulation.

STATE

California State Health and Safety Code, Section 41700, requires that "no person shall discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerate number of persons or to the public, or which endanger the comfort, repose, health, or safety of any such persons or the public, or which cause, or have a natural tendency to cause, injury or damage to business or property."

LOCAL

As part of the Energy Commission's licensing process, in lieu of issuing a construction permit to the applicant for the Salton Sea Unit 6 Project, the ICAPCD has prepared and presented to the Commission a Final Review or Final Determination of Compliance (FDOC) equivalent (District 2003b). The FDOC evaluates whether and under what conditions the proposed project will comply with the District's applicable rules and regulations, as described below.

Regulation I - General

Rule 109 — Source Sampling

This rule outlines the facilities required for source sampling.

Rule 111 — Equipment Breakdown

This rule defines equipment breakdown and details the requirements necessary in the case of an equipment breakdown situation.

Regulation II — Permits

This regulation sets forth the regulatory framework of the application for and issuance of construction and operation permits for new, altered and existing equipment.

Rule 201 — Permits Required

This rule identifies the types of permits required. A permit to operate is required for the project.   An application has been submitted to ICAPCD.

Rule 207 — New and Modified Stationary Source Review

This rule outlines the emissions standards, the offset requirements and conditions, the procedure for calculation of offsets and air quality impact analysis. The specific applicable requirements of this rule are as follows:

C.1 Best Available Control Technology

Best Available Control Technology is required for any new emissions unit that has a potential to emit of 25 lbs/day or more of any non-attainment pollutant or its precursors. Rule 101 lists hydrocarbons and nitrogen oxides as ozone precursors; and, hydrocarbons, nitrogen oxides and sulfur oxides as precursors to PM10, the air basins two non-attainment pollutants. The regulations do not specify ammonia as a regulated non-attainment pollutant.

Additionally, Best Available Control Technology is required for any new emissions unit that has a potential to emit 55 lbs/day or more of hydrogen sulfide.

C.2 Offset Requirements

Offsets are required for new stationary sources with a daily potential to emit for reactive organic compounds, nitrogen oxides, sulfur oxides, PM10 or carbon monoxide that exceed 137 lbs/day.

C.3 Location of Offsets and Offset Ratios

This regulation notes that emission increases subject to offset requirements must be offset at a ratio of 1.2 to 1 when using emission reductions within 50 miles of the source being offset. The APCO will determine the offset ratio when emission reductions are within the air basin but greater than 50 miles from the source, where the minimum ratio that can be determined is 1.2:1 and the maximum ratio is 3:1.

C.5 Additional Source Requirements

Section C.5.b.1 notes that “Emissions from a new or modified Emissions Unit shall not cause or make worse a violation of an Ambient Air Quality Standard”. And that “In making this determination the Air Pollution Control Officer shall take into account the increases in minor and secondary source emissions as well as the mitigation of emissions through Offsets obtained pursuant to this regulation.

Section C.5.b.2 allows new or modified Emission Units to be exempted from the Requirements of Section C.5.b.2 at the discretion of the Air Pollution Control Officer provided: 1) offsets have been provided for all increases in permitted emissions including fugitive, cargo carrier, and Secondary Emissions, or 2) if the Emissions Unit is not subject to the Best Available Control Technology and Offset requirements of this Rule.

Section C.5.c requires that the owner or operator of the proposed new Emission Unit demonstrate that all Stationary Sources owned and operated within the state of California are in compliance or a schedule for compliance with all applicable emission limitations and standards.

D.9 Power Plants

This section provides the permit review requirements for power plants for which an Application for Certification has been accepted by the California Energy Commission.

F. Air Quality Impact Analysis

This section specifies the requirements for performing an air quality impact analysis, if required by the Air Pollution Control Officer.

<u>Regulation III — Fees</u>

Rule 309 – Air Toxic “Hot Spots” Information and Assessment

Facilities are subject to an annual fee to recover the reasonable anticipated costs incurred by the State Air Resources Board, the District, and the State Department of Health Services in implementing and administering the Air Toxic "Hot Spots" information and Assessment Act.

Regulation IV - Prohibitions

This regulation sets forth the restrictions for visible emissions, odor nuisance, various air emissions, and fuel contaminants.

Rule 400 – Fuel Burning Equipment – Oxides of Nitrogen

This rule applies to nitrogen oxides emissions from new and existing stationary fuel burning equipment. The discharge limit of nitrogen oxides is 140 lb/hr (NO_2). Compliance demonstration, including test methods and reporting requirements is provided.

Rule 401 – Opacity of Emissions

This rule restricts visible emissions from a single source for more than three minutes in any one hour from being as dark or darker than that designated No. 1 on the Ringelmann Chart (US Bureau of Mines) or less than 20% opacity.

Rule 403 – General Limitations on the Discharge of Air Contaminants

This rule applies to emissions from any single unit; and restricts the discharge of particulate matter, including lead and lead compounds, air contaminants, and combustion contaminants. Test methods and limits are provided.

Rule 405 – Sulfur Compounds Emission Standards, Limitations and Prohibitions

This rule applies to emissions of sulfur compounds from any single source of emissions. A limit of 0.2 percent by volume (SO_2) is specified for sulfur compounds. Stationary fuel burning equipment limits are specified at 500 parts per million by volume (SO_2), or 200 lb/hr of sulfur compounds (SO_2). The sulfur content limit of fuels are specified at 50 grains per 100 cubic feet of gaseous fuel, calculated as H_2S at standard conditions, or 0.5 percent by weight.

Rule 407 — Nuisance

This rule restricts the discharge of any contaminant in quantities that cause or have a natural ability to cause injury, damage, nuisance or annoyance to businesses, property or the public.

Regulation VIII

Rule 800 - Fugitive Dust Requirement for Control of Fine Particulate Matter (PM-10)

This rule requires that the applicant prevent, reduce or mitigate fugitive dust emissions from the project site by implementing and maintaining USEPA defined Reasonably Available Control Measures (RACM), unless the implementation of such RACM endangers or could endanger the health or safety of the public. A list of RACM is provided in the rule. Details are provided for track out/carry out, unpaved haul/access roads, unpaved roads, bulk material handling, material transport, and haul trucks.

SETTING

METEOROLOGICAL CONDITIONS

The SSU6 Project site is located in the Imperial Valley, just beyond the southeast shoreline of the Salton Sea. Imperial Valley is the southwest part of the Colorado Desert that merges northwestward into the Coachella Valley near the northern shore of the Salton Sea. The immediate area surrounding the project site is dominated by agriculture, geothermal power plants and the Salton Sea, including Salton Sea wildlife habitat areas.

Imperial County is classified as having a desert climate, characterized by low precipitation, hot summers and mild winters. The coastal mountains on the western edge of the Imperial Valley block the cool, damp marine air found in the California coast, which results in low relative humidity conditions. The flat terrain of the valley floor in the Salton Sea area and the strong temperature differentials created by intense solar heating produce moderate winds and deep thermal convection currents. The valley area experiences surface inversions virtually every day of the year that are usually broken by solar heating. Air stagnation conditions can occur for a day or for a few days during the presence of a Pacific high-pressure system.

Temperature and precipitation data from the nearest representative local cooperative station, Brawley 2 SW, indicates that July is the hottest month with an average maximum temperature of 106.5°F, an average minimum temperature of 74.4°F, and an average mean temperature of 90.5°F. January is the coldest month with an average maximum temperature of 69.3°F, an average minimum temperature of 35.7°F, and an average mean temperature of 54.0°F. Annual average rainfall is 3.05 inches. December receives the most rain, averaging 0.41 inches; June receives the least, averaging 0.01 inches. Monthly average wind speeds in the region range from 6.6 miles per hour (mph) in October to 9.5 mph in July. Winds average 7.8 mph annually. Winds in the valley are primarily from the west to east throughout the year, but have a secondary southeast component in the fall. High winds, some that can create dust storms, are occasionally experienced in the Imperial Valley region. Solar isolation data suggests that 90 percent of possible sunshine occurs in the region. The cloudiest periods occurs in winter while the sunniest periods are in the summer.

Available temperature and rainfall data from Imperial essentially mirrors the Brawley data with nearly identical temperature data and average rainfall, but shows that January is the month with the greatest rainfall, averaging 0.50 inches. Rainfall in Imperial County is highly variable, with the rainfall from single heavy storms exceeding the entire rainfall totals of other dryer years.

Wind movements based on Imperial County Airport data for the period 1995-1999 show an average wind speed of 7.6 miles per hour, and in general, the winds predominantly from the west to southwest.

Wind movements based on Niland monitoring station data for 2002 show an average wind speed of 6.9 miles per hour and show that winds predominately are from the southeast with another large component from the west. The winds from the southeast generally show low wind speeds while the winds from the west show comparatively higher wind speeds.

Other meteorological data collected from other sources in and around the Salton Sea show different wind speed and direction patterns. Staff believes that the Salton Sea creates a microclimate that affects the meteorological conditions surrounding the sea, which creates the potential for significant variability in the specific meteorological conditions at different sites surrounding the sea.

EXISTING AIR QUALITY

The USEPA and the California Air Resources Board (CARB) are both authorized to establish allowable maximum ambient concentrations of air pollutants, called ambient air quality standards (AAQS). The state AAQS, established by CARB, are typically more restrictive than the federal AAQS, which are established by the USEPA. The state and federal air quality standards are listed in **AIR QUALITY Table 1**. As indicated in Table 1, the averaging times for the various air quality standards (the duration over which they are measured) range from one-hour to an annual basis. The standards are read as a concentration, in parts per million (ppm), or as a weighted mass of material per a volume of air, in milligrams or micrograms of pollutant per cubic meter of air (mg/m^3 and $\mu g/m^3$, respectively).

In general, an area is designated as attainment for a specific pollutant if the concentrations of that air contaminant do not exceed the standard. Likewise, an area is designated as non-attainment for an air contaminant if that standard is violated. Where not enough ambient data are available to support designation as either attainment or non-attainment, the area would be designated as unclassified. Unclassified areas are normally treated the same as attainment areas for regulatory purposes. An area can be attainment for one air contaminant and non-attainment for another, or attainment for the federal standard and non-attainment for the state standard for the same contaminant. The entire area within the boundaries of a district or air basin is usually evaluated to determine the district's attainment status. **AIR QUALITY Table 2** shows the area designation status of the Salton Sea air basin for each criteria pollutant for both the federal and state ambient air quality standards. The federal classifications range from moderate to extreme.

AIR QUALITY Table 1
Federal and State Ambient Air Quality Standards

Pollutant	Averaging Time	Federal Standard	California Standard
Ozone (O_3)	1 Hour	0.12 ppm (235 μg/m^3)	0.09 ppm (180 μg/m^3)
	8 Hour	0.08 ppm (160 μg/m^3)	—
Carbon Monoxide (CO)	8 Hour	9 ppm (10 mg/m^3)	9 ppm (10 mg/m^3)
	1 Hour	35 ppm (40 mg/m^3)	20 ppm (23 mg/m^3)
Nitrogen Dioxide (NO_2)	Annual Average	0.053 ppm (100 μg/m^3)	—
	1 Hour	—	0.25 ppm (470 μg/m^3)
Sulfur Dioxide (SO_2)	Annual Average	0.03 ppm (80 μg/m^3)	—
	24 Hour	0.14 ppm (365 μg/m^3)	0.04 ppm (105 μg/m^3)
	3 Hour	0.5 ppm (1300 μg/m^3)	—
	1 Hour	—	0.25 ppm (655 μg/m^3)
Respirable Particulate Matter (PM_{10})	24 Hour	150 μg/m^3	50 μg/m^3
	Annual Arithmetic Mean	50 μg/m^3	20 μg/m^3
Fine Particulate Matter ($PM_{2.5}$)	Annual Arithmetic Mean	15 μg/m^3	12 μg/m^3
	24 Hour	65 μg/m^3	—
Sulfates (SO_4)	24 Hour	—	25 μg/m^3
Lead	30 Day Average	—	1.5 μg/m^3
	Calendar Quarter	1.5 μg/m^3	—
Hydrogen Sulfide (H_2S)	1 Hour	—	0.03 ppm (42 μg/m^3)
Vinyl Chloride (chloroethene)	24 Hour	—	0.010 ppm (26 μg/m^3)
Visibility Reducing Particulates	1 Observation (8 hour)	—	Insufficient amount to produce an extinction coefficient of 0.23 per kilometer due to particles when the relative humidity is less than 70 percent.

AIR QUALITY Table 2
Federal and State Attainment Status for the Salton Sea Air Basin

Pollutants	Federal Classification	State Classification
Ozone	Transitional Non-Attainment [a]	Moderate Non-Attainment
PM_{10}	Moderate Non-Attainment [b]	Non-Attainment
CO	Unclassified/Attainment	Unclassified
NO_2	Attainment	Attainment
SO_2	Attainment	Attainment
H_2S	---	Unclassified

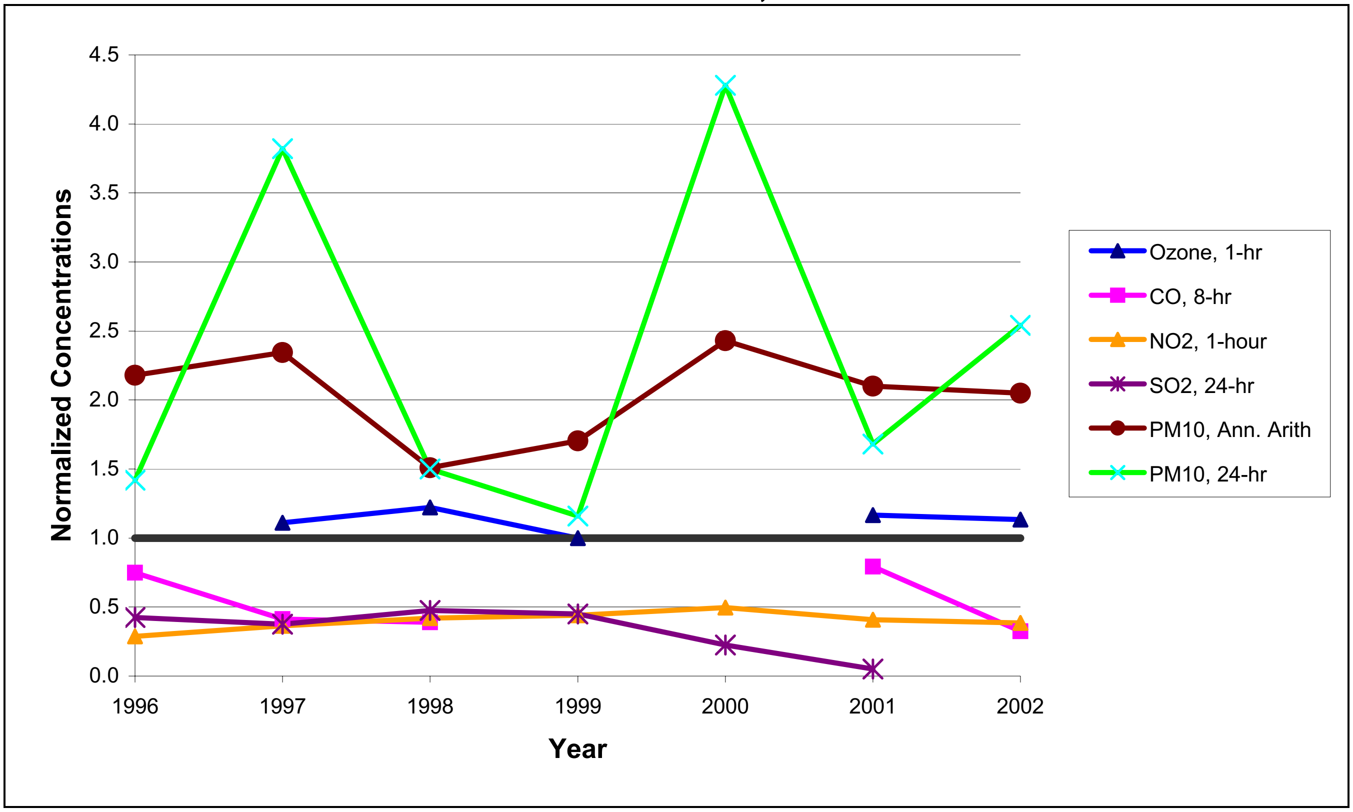
Note(s):

a. Clean Air Act Section 185A (Previously called Transitional) areas were designated as an ozone non-attainment area as of the date of enactment of the Clean Air Act Amendments of 1990, and have not violated the national primary ambient air quality standard for ozone for the 36-month period commencing on January 1, 1987, and ending on December 31, 1989. Twelve areas were classified transitional in 1991. Prior Designation retained by operation of Law, but without measured violations.

b. Currently, the area is officially still a moderate non-attainment area even though available data suggests the area would attain standards except for the influence of sources outside the U.S. For the USEPA to reclassify Imperial County as being in attainment, Imperial County must request reclassification to attainment.

In **AIR QUALITY Figure 1**, the short term normalized concentrations based on data collected from various air monitoring stations are provided from 1996 to 2002 for ozone, CO, NO_2, PM_{10}, and SO_2. Air monitoring station data for ozone and PM_{10} are from Niland-English Road, CO data are from El Centro-9th Street, NO_2 data are from Calexico-East and El Centro (2002), and SO_2 data are from Calexico-East. Normalized concentrations represent the ratio of the highest measured concentrations in a given year to the most-stringent applicable national or state ambient air quality standard. Therefore, normalized concentrations lower than one indicate that the measured concentrations were lower than the most-stringent ambient air quality standard.

AIR QUALITY Figure 1
Normalized Maximum Short-Term Historical Air Pollutant Concentrations, 1996-2002



As shown in **AIR QUALITY Figure 1**, CO, NO_2, and SO_2 are all lower than the most-stringent ambient air quality standards between 1994 and 2002. These pollutants are also classified as in attainment or unclassified per the National and State Ambient Air Quality Standards. Following is a more in-depth discussion of the ambient air quality conditions in the project area, which are used as the basis for the background concentrations.

Ozone

In the presence of ultraviolet radiation, both NO_x and VOC go through a number of complex chemical reactions to form ozone. NO_x and VOC emissions from vehicles and stationary sources from within the air basin and the migration of pollution from other air basins and Mexico, in conjunction with daytime wind flow patterns, mountain barriers, a persistent temperature inversion and intense sunlight, result in ozone forming conditions in Imperial County. **AIR QUALITY Table 3** summarizes the best representative ambient ozone data collected from three different monitoring stations close to the project site. The table includes the maximum hourly concentration and the number of days above the State standards. The Salton Sea air basin is classified as a transitional non-attainment area for ozone per the National Ambient Air Quality Standards, and a moderate non-attainment area for ozone per the California Ambient Air Quality Standards.

AIR QUALITY Table 3
Ozone Air Quality Summary, 1994-2001

Year	Niland- English Rd.				Westmorland – West 1st St.				El Centro – 9th St.			
	% Data	Days Above CAAQS	Max. 1-hr Level (ppm)	Month of Max. 1-hr Level	% Data	Days Above CAAQS	Max. 1-hr Level (ppm)	Month of Max. 1-hr Level	% Data	Days Above CAAQS	Max. 1-hr Level (ppm)	Month of Max. 1-hr Level
1994	---	---	---	---	---	---	---	---	100	29	0.130	Mar
1995	---	---	---	---	---	---	---	---	99	31	0.150	Oct
1996	---	---	---	---	---	---	---	---	84	41	0.140	Jun
1997	10	1	0.100	Oct	---	---	---	---	95	29	0.130	Jun
1998	86	5	0.110	Jul	74	10	0.120	Jul	88	12	0.130	Nov
1999	40	0	0.090	Jan	27	24	0.145	Oct	37	9	0.140	Jan
2000	---	---	---	---	---	---	---	---	---	---	---	---
2001	98	2	0.105	Oct	36	1	0.105	Oct	60	13	0.135	Sep
2002	99	5	0.102	Jun	99	0	0.092	May	99	19	0.122	Mar
California Ambient Air Quality Standard (CAAQS): 0.09 ppm National Ambient Air Quality Standard: 0.12 ppm Source: CARB web site, http://www.arb.ca.gov/adam/, Accessed October 2002.												

The Niland – English Road monitoring station, located only 5.6 miles from the project site, measures the most representative existing ambient air quality data for the proposed project site because of its similar desert-like characteristics and proximity to the proposed project site. The El Centro – 9th Street monitoring station, having the longest data record, suggests that ozone levels may have peaked in the mid 1990's and are now trending toward lower concentrations. The El Centro – 9th Street monitoring station is located 26 miles from the project site.

Carbon Monoxide (CO)

The highest concentrations of CO occur when low wind speeds and a stable atmosphere trap the pollution emitted at or near ground level in what is known as the stable boundary layer. These conditions occur frequently in the wintertime late in the afternoon, persist during the night and may extend one or two hours after sunrise. Since mobile sources (motor vehicles) are the main cause of CO, ambient concentrations of CO are highly dependent on motor vehicle activity. In fact, the peak CO concentrations occur during the rush hour traffic in the morning and afternoon. Carbon monoxide concentrations in the state have declined significantly due to two state-wide programs: 1) the 1992 wintertime oxygenated gasoline program, and 2) Phases I and II of the reformulated gasoline program. New vehicles with oxygen sensors and fuel injection systems have also contributed to the decline in CO levels in the state. However, Mexico does not have equivalent programs, which in part cause high CO concentrations near the border, particularly near Mexicali.

CO is considered a local pollutant as it is found in high concentrations only near the source of emission. Though mobile sources are the principal source of CO emissions, high levels can also be generated from fireplaces and wood-burning stoves.

AIR QUALITY Table 4 summarizes the best representative ambient carbon monoxide data collected from three different monitoring stations close to the project site. The table includes the maximum 1-hour and 8-hour concentrations and the number of days above the State standards. The Salton Sea air basin is classified as an attainment area for CO per the National Ambient Air Quality Standards and is unclassified under the California Ambient Air Quality Standards.

AIR QUALITY Table 4
CO Air Quality Summary, 1994-2001

Year	El Centro – 9th St.				Calexico-East				Calexico-Ethel Street			
	% Data	Max. 1-hr Average (ppm)	Max. 8-hr Average (ppm)	Days Above 8-hr CAAQS	% Data	Max. 1-hr Average (ppm)	Max. 8-hr Average (ppm)	Days Above 8-hr CAAQS	% Data	Max. 1-hr Average (ppm)	Max. 8-hr Average (ppm)	Days Above 8-hr CAAQS
1994	---	---	---	---	---	---	---	---	63	30.6	13.06	10
1995	---	---	---	---	---	---	---	---	99	32.0	22.93	17
1996	100	12.0	6.75	0	63	22.0	8.74	0	100	27.0	22.1	11
1997	100	6.0	3.71	0	99	21.0	16.29	4	99	24.0	17.84	13
1998	75	7.0	3.50	0	95	18.4	13.0	3	96	23.5	14.36	10
1999	---	---	---	---	97	14.0	9.37	1	96	22.9	17.86	13
2000	---	---	---	---	35	---	11.30	1	96	---	15.47	7
2001	76	---	7.14	0	65	---	6.44	0	99	---	12.33	6
2002	98	---	2.93	0	---	---	7.41	0	---	---	11.56	4

California Ambient Air Quality Standard: 1-hr, 20 ppm; 8-hr, 9 ppm
National Ambient Air Quality Standard: 1-hr, 35 ppm; 8-hr, 9 ppm
Source: CARB Air Quality Data CD, 2000 and CARB web site, http://www.arb.ca.gov/adam/, Accessed 2002/2003.

As **AIR QUALITY Table 4** shows, the maximum one-hour and eight-hour CO concentrations are less than the California Ambient Air Quality Standards at the El Centro – 9th Street air monitoring station since at least 1996 (no data available prior to 1996). This is the closest monitoring station, located 26 miles from the proposed project site, having CO air quality data. The Calexico peak concentration data is not considered to be representative of the project site.

Nitrogen Dioxide (NO_2)

Approximately 90 percent of the NO_x emitted from combustion sources is NO, while the balance is NO_2. NO is oxidized in the atmosphere to NO_2 but some level of photochemical activity is needed for this conversion. This is why the highest concentrations of NO_2 occur during the fall and not in the winter when atmospheric conditions favor the trapping of ground level releases but lack significant photochemical activity (less sunlight). In the summer the conversion rates of NO to NO_2 are high but the relatively high temperatures and windy conditions (atmospheric unstable conditions) disperse pollutants, preventing the accumulation of NO_2 to levels approaching the 1-hour ambient air quality standard. The formation of NO_2 in the summer with the help of the ozone is according to the following reaction.

$$NO + O_3 \Downarrow NO_2 + O_2$$

In urban areas, the ozone concentration level is typically high. That level will drop substantially at night as the above reaction takes place between ozone and NO. This reaction explains why, in urban areas, ozone concentrations at ground level drop, while aloft and in downwind rural areas (without sources of fresh NO_x emissions) ozone concentrations can remain relatively high.

AIR QUALITY Table 5 summarizes the best representative ambient nitrogen dioxide data collected from three different monitoring stations close to the project site. The table includes the maximum 1-hour and annual concentrations. The Salton Sea air basin is classified as an attainment area for NO_2 per the National Ambient Air Quality Standards and the California Ambient Air Quality Standards.

AIR QUALITY Table 5
NO_2 Air Quality Summary, 1994-2001

Year	El Centro – 9th Street			Calexico-East			Calexico-Ethel		
	% Data	Max. 1-hr Average (ppm)	Max. Annual Average (ppm)	% Data	Max. 1-hr Average (ppm)	Max. Annual Average (ppm)	% Data	Max. 1-hr Average (ppm)	Max. Annual Average (ppm)
1994	---	---	---	---	---	---	68	0.227	---
1995	---	---	---	---	---	---	99	0.217	0.016
1996	---	---	---	65	0.072	---	99	0.164	0.014
1997	---	---	---	95	0.091	0.011	74	0.128	0.015
1998	---	---	---	91	0.105	0.012	74	0.257	---
1999	---	---	---	98	0.110	0.013	98	0.286	0.018
2000	---	---	---	76	0.124	0.012	96	0.192	0.019
2001	47	0.086	---	81	0.102	0.010	76	0.139	0.014
2002	99	0.096	0.010	---	0.130	0.011	---	0.138	0.013

California 1-hr Ambient Air Quality Standard: 0.25 ppm
National Annual Ambient Air Quality Standard: 0.053 ppm
Source: CARB Air Quality Data CD, 2000, and CARB web site, http://www.arb.ca.gov/adam/, Accessed 2002/2003.

As shown in **AIR QUALITY Table 5** the maximum one-hour and annual concentrations of NO_2 at the El Centro 9th Street air monitoring station are lower than the California and National Ambient Air Quality Standards. This monitoring station is considered by staff to provide the most representative data for the project site since it is the closest station to the project site. Data from the Calexico-East monitoring station, located 36 miles from the project site, also shows no exceedances of the state 1-hr standard and federal annual standard.

Inhalable Particulate Matter (PM_{10})

PM_{10} can be emitted directly or it can be formed many miles downwind from emission sources when various precursor pollutants interact in the atmosphere. Gaseous emissions of pollutants like NO_x, SO_x and VOC from turbines, and ammonia from NO_x control equipment, given the right meteorological conditions, can form particulate matter in the form of nitrates (NO_3), sulfates (SO_4), and organic particles. These pollutants are known as secondary particulates, because they are not directly emitted but are formed through complex chemical reactions in the atmosphere.

PM nitrate (mainly ammonium nitrate) is formed in the atmosphere from the reaction of nitric acid and ammonia. Nitric acid in turn originates from NO_x emissions from combustion sources. The nitrate ion concentrations during the wintertime are a significant portion of the total PM_{10}, and should be even a higher contributor to particulate matter of less than 2.5 microns ($PM_{2.5}$). The nitrate ion is only a portion of the PM nitrate, which can be in the form of ammonium nitrate (ammonium plus nitrate ions) and some as sodium nitrate. If the ammonium and the sodium ions associated with the nitrate ion are taken into consideration, PM nitrate contributions to the total PM would be even more significant.

The air agencies in California are now deploying $PM_{2.5}$ ambient air quality monitors throughout the state. $PM_{2.5}$ ambient air quality attainment plans, if needed, are due to the USEPA by 2005.

AIR QUALITY Table 6 summarizes the most representative ambient PM_{10} data collected from three different monitoring stations close to the project site. The table includes the maximum daily average, annual geometric average and annual arithmetic average concentrations. The Salton Sea air basin is classified as a moderate non-attainment area for PM_{10} per the National Ambient Air Quality Standards, and a non-attainment area for PM_{10} per the California Ambient Air Quality Standards. Initially California was to have attained PM_{10} standards in Imperial County by December 31, 1994. Not meeting the standards by that date would have forced the USEPA to reclassify the area as a severe non-attainment area, except that California demonstrated to the USEPA that standards would have been met except for emissions emanating from outside the U.S. Currently, the area is officially still moderate non-attainment area even with the USEPA's finding of attainment. For the USEPA to reclassify Imperial County as being in attainment, Imperial County must request reclassification to attainment. Staff considers the project area to be a non-attainment area since the reason for the non-attainment status is irrelevant when assessing project contributions to the health-based PM_{10} AAQS.

AIR QUALITY Table 6
PM_{10} Air Quality Summary, 1994-2001

Year	% Data	Days Above CAAQS* (Calc)	Maximum Daily Avg. (μg/m^3)	Month of Maximum Daily Level	Annual Arithmetic Average
	Niland – English Rd.				
1994	---	---	---	---	---
1995	---	---	---	---	---
1996	50	36	71.0	Jul	43.6
1997	52	72	191.0	Oct	46.9
1998	84	24	75.0	Jul	30.2
1999	100	42	58.0	Jun	34.1
2000	94	120	214.0	Sep	48.6
2001	87	84	84.0 [a]	Apr	42
2002	---	90	127	May	41
	Westmorland – West 1st Street				
1994	60	36	120.0	Aug	51.5
1995	95	78	107.0	Mar	38.9
1996	99	120	229.0	Jul	49.3
1997	94	72	213.0	Oct	43.5
1998	99	54	81.0	Apr	32.4
1999	100	102	130.0	Jul	44.2
2000	94	126	250.0	Sep	54.1
2001	92	151	125.0 [a]	Apr	57
2002	---	132	297	May/Aug	57
	Brawley – Main St.				
1994	91	108	126.0	Mar	51.9
1995	96	108	122.0	Mar	45.1
1996	100	132	257.0	Jul	47.1
1997	93	84	532.0	Oct	50.7
1998	90	54	81.0	Jan	38.1
1999	93	96	89.0	May	42.1
2000	93	114	204.0	Sep	51.3
2001	93	85	120.0	Apr	42
2002	---	72	220	May	45

California Ambient Air Quality Daily Standard: 50 μg/m^3
National Ambient Air Quality Daily Standard: 150 μg/m^3
California Annual Arithmetic Mean AAQS: 20 μg/m^3
National Annual Arithmetic Mean AAQS: 50 μg/m^3
Source: CARB Air Quality Data CD, 2000, and CARB web site, http://www.arb.ca.gov/adam/, Accessed 2002/2003.

Note (a): Except for measurements of 377 σg/m^3 and 647 σg/m^3, and at Niland and Westmorland, respectively, due to high winds throughout the Imperial and Mexicali Valley on August 17, 2001, all of the remaining year's PM_{10} data show compliance with the NAAQS. The second highest measurements for Niland and Westmorland are shown in this table.

* Days above the state standard (calculated): Because PM_{10} is monitored approximately once every six days, the potential number of violation days is calculated by multiplying the actual number of days of violations by six.

As **AIR QUALITY Table 6** indicates, the project area annually experiences a number of violations of the state 24-hour PM_{10} standard. The Niland – English Road monitoring station, located only 5.6 miles from the project site, is considered the most representative existing ambient air quality data for the proposed project site. PM_{10} concentrations recorded at Niland-English Road also consistently exceed the 24-hour state standard, although the federal annual PM_{10} standard was not exceeded between 1996 and 2000.

Fine Particulate Matter ($PM_{2.5}$)

While the $PM_{2.5}$ NAAQS were issued in 1997, their implementation has been delayed. Currently, states have until February 15, 2004 to recommend to the USEPA which areas should be designated as attainment and non-attainment. USEPA will provide final designations by December 15, 2004. States have three years from the time of final designation (December 2007) to provide $PM_{2.5}$ attainment plans in a state implementation plan (SIP).

The $PM_{2.5}$ CAAQS were issued in 2003, and a state attainment status determination is scheduled to occur in early 2004. There are no attainment planning requirements associated with the California ambient standards.

As **AIR QUALITY Table 7** indicates, the 1-year 98th percentile 24-hour average and annual average $PM_{2.5}$ concentration levels have generally been declining at the Brawley – Main Street, El Centro – 9th Street, and Calexico – Ethel Street monitoring stations since at least 1999. These monitoring stations are located approximately 13 miles, 26 miles, and 35 miles, respectively, from the proposed project site. The 3-year 98th percentile 24-hour average concentrations at all three stations have been below the proposed CAAQS of 65 $\sigma g/m^3$ since at least 1999. The 3-year average of annual arithmetic means (national annual average) measured at Brawley – Main Street and El Centro – 9th Street monitoring stations, located closest to the proposed project site, are below the proposed NAAQS of 15 $\sigma g/m^3$. The Salton Sea air basin is influenced by emissions from Mexico, primarily Mexicali, which may in part cause the Calexico monitoring site to exceed the annual ambient standard. Due to the border pollution effect, and its potential interpretation, it is uncertain how the EPA will determine attainment status of the $PM_{2.5}$ standards for the air basin.

AIR QUALITY: Table 7
$PM_{2.5}$ Air Quality Summary, 1999-2001 ($\sigma g/m^3$)

Year	Max. Daily Average	1-Yr 98th Percentile of Max. Daily Average	3-Yr. Avg. 98th Percentile of Max. Daily Average	Annual Average	3-Yr. Annual Average
	Brawley – Main St.				
1999	44.2	43.2	---	11.2	---
2000	55.4	41.5	---	12.3	---
2001	42.2	30.2	38.3	11.1	11.5
2002	25.9	22.3	31.3	10.2	11.2
	El Centro – 9th St.				
1999	52.5	39.5	---	11.8	---
2000	55.6	39.3	---	10.4	---
2001	23.5	17.6	32.1	8.9	10.3
2002	28.9	23.4	26.8	9.3	9.5
	Calexico – Ethel St.				
1999	51.6	39.5	---	15.2	---
2000	84.2	56.0	---	16.9	---
2001	60.2	50.4	48.6	14.9	15.7
2002	46.5	44.1	50.2	15.1	15.6

Proposed National Ambient Air Quality Standards:
3-Year Average - 98th Percentile of 24-Hr Avg. Concentrations, 65 $\sigma g/m^3$;
3-Year Average of Annual Arithmetic Mean (National Annual Average), 15 $\sigma g/m^3$
Source: CARB web site, http://www.arb.ca.gov/adam/, Accessed 2002/2003.

Sulfur Dioxide (SO_2)

Sulfur dioxide is typically emitted as a result of the combustion of a fuel that contains sulfur. Fuels such as natural gas contain very little sulfur and consequently have very low SO_2 emissions when combusted. By contrast, fuels high in sulfur content such as certain types of coal or heavy fuel oils emit very large amounts of SO_2 when combusted.

The Salton Sea air basin is designated attainment for all the SO_2 state and federal ambient air quality standards. **AIR QUALITY Table 8** shows the historic 1-hour, 24-hour and annual average SO_2 concentrations measured at the Calexico-East and Calexico-Ethel Street monitoring stations. As **AIR QUALITY Table 8** shows, concentrations of SO_2 are far below the state and federal SO_2 ambient air quality standards.

AIR QUALITY Table 8
SO_2 Air Quality Summary, 1994-2000

Year	Calexico-East					Calexico-Ethel Street				
	% Data	Max. 1-hr Average (ppm)	Max. 3-hr Average (ppm)	Max. 24-hr Average (ppm)	Annual Average (ppm)	% Data	Max. 1-hr Average (ppm)	Max. 3-hr Average (ppm)	Max. 24-hr Average (ppm)	Annual Average (ppm)
1994	---	---	---	---	---	51	0.060	---	0.020	0.007
1995	---	---	---	---	---	46	0.039	---	0.018	0.005
1996	66	0.036	0.020	0.010	0.0017	89	0.036	0.028	0.017	0.004
1997	89	0.035	0.026	0.015	0.0020	83	0.040	0.031	0.015	0.003
1998	17	0.026	0.021	0.009	0.0029	85	0.035	0.026	0.019	0.003
1999	---	---	---	---	---	98	0.028	0.024	0.018	0.002
2000	---	---	---	---	---	97	---	0.022	0.009	0.002
2001	---	---	---	---	---	94	---	---	0.002	0.001

California Hourly Ambient Air Quality Standard: 0.250 ppm
California 24-hr Ambient Air Quality Standard: 0.040 ppm
National Annual Ambient Air Quality Standard: 0.030 ppm
Source: CARB Air Quality Data CD, 2000 and CARB web site, http://www.arb.ca.gov/adam/ Accessed 2002/2003.

The Calexico-East monitoring station, located 36 miles from the project site, is the closest monitoring station with representative SO_2 air quality data. This station, however, is influenced by commercial and industrial activities near Calexico, and therefore, the values presented are likely to be conservative estimates of the background levels near the proposed project site. No other ambient air quality monitoring stations in Imperial County record SO_2 concentrations.

Hydrogen Sulfide (H_2S)

The Niland - English Road air monitoring station was originally established to monitor the ambient levels of H_2S in the geothermal area of the Salton Sea. Because of extensive operating and quality control issues with the H_2S monitor, H_2S monitoring at this station was discontinued. Due to a lack of data to the contrary, the area is designated as an unclassified area. The Imperial County APCD recommended a background H_2S level of 24.6 $\sigma g/m^3$ (0.018 ppm) based on an average level of the available data (1993, 1994) monitored before Units 1, 2, and 3, Vulcan, and Hoch were retrofitted with biofilter controls (District, 2003a, page 10, Table 1).

Summary

In summary, staff recommends using the background ambient air concentrations in **AIR QUALITY Table 9** for modeling and evaluating potential ambient air quality impacts from the proposed project.

AIR QUALITY Table 9
Staff Recommended Background Concentrations

Pollutant	Averaging Time	Year	Location	Concentration ($\sigma g/m^3$)	Concentration (ppm)
Ozone	1 Hour	2001	Niland	210	0.105
Particulate Matter	Annual Arithmetic Mean	2000	Niland	48.6	---
	24 Hour	2000	Niland	115	---
Carbon Monoxide	8 Hour	1998	El Centro	4,000	3.5
	1 Hour	1998	El Centro	8,000	7.0
Nitrogen Dioxide	Annual Average	2002	El Centro	19	0.010
	1 Hour	2002	El Centro	180	0.096
Sulfur Dioxide	Annual Average	1999	Calexico	5	0.002
	24 Hour	1999	Calexico	47	0.018
	3 Hour	1999	Calexico	63	0.024
	1 Hour	1999	Calexico	73	0.028
Hydrogen Sulfide	1 Hour	1993/ 1994	Niland	24.6[1]	0.018

[1] – Data is from the ICAPCD's analysis of available monitoring data.

The maximum values from the closest representative monitoring station to the proposed project site, over the most recent three years of available data, where the year coverage (% data) is at least 75%, have been selected to represent the background ambient air quality for the proposed project site. In order to account for high wind-related PM_{10} events, the 24-hour PM_{10} background selected is the highest 4th high. This 24-hour PM_{10} background concentration is considered to be more realistic normal worst-case background to which any and all modeling results can be added. If staff chose the background as the highest high that occurred during high wind events, then only modeling results from the days with similar high winds could be added to the background. Additionally, the standard is focused on man-made pollution impacts, which are not represented during high wind dust storm events. Staff is also justifying the use of the highest 4th high as it is used to determine attainment with the 24-hour PM_{10} NAAQS.

PROJECT DESCRIPTION AND EMISSIONS

This section describes the project construction and the operating design and criteria pollutant control devices as described in the Salton Sea Unit 6 Project Application for Certification (CEOE 2002a).

CONSTRUCTION

The proposed project construction schedule is expected to take 26 months. On-site building of the facility is expected to take 20 months (CEOE 2002a, DR #56). Construction of the power plant facility will start in the sixth month. Construction and startup of the power plant from the start of mobilization to commercial operation is expected to take at least 19 months. Construction of the new electrical transmission lines is estimated to take approximately 12 months. During the construction period, air emissions will be generated from the exhaust of heavy equipment and well flow testing, and fugitive dust from activity such as grading, excavating, and well drilling. Well flow testing will not be necessary for the onsite plant injection wells. Fugitive dust emissions will occur due to the temporary disturbance of an estimated 479.5 acres (CEOE 2002a, Table 3.2-2, pg. 3-50), including the energy facility, construction staging and lay-down areas, production and injection wells, pipelines, interconnection poles, access roads, parking areas, and pull sites. **AIR QUALITY Tables 10 through 12** summarize the estimated levels of criteria pollutants generated from the construction activities at the Salton Sea Unit 6 Project site (CEOE 2002a).

Air Quality Table 10
SSU6 Project Estimated Maximum Hourly Construction Emissions
For the Power Plant, Pipelines, and Transmission Lines, lb/hr

Source	NO_x	CO	VOC	SO_x	PM_{10}	NH_3	H_2S
Construction Equipment [a]	26.42	19.78	3.82	0.48	1.49	---	---
Delivery Trucks [a]	10.69	3.16	0.83	0.10	0.35	---	---
Worker Travel [a]	7.62	89.31	9.72	0.06	0.20	---	---
Fugitive Dust [b]	---	---	---	---	11.7	---	---
Sub-Total [c]	41.0	108.3	13.4	0.60	13.4	---	---
Well Drilling	25.97	3.17	0.36	0.73	1.07	---	---
Well Flow Testing	---	---	0.46[d]	---	64.8	47.2	11.8
Total	67	111	14.2	1.3	79.3	47.2	11.8

Source: CEOE 2002a. Detailed calculations located in Appendix G, Tables G-1 through G-1.6 (fugitive dust), G-2 (well drilling), G-3 to G-3.11 (construction equipment, worker travel, and delivery trucks), and G-4 (well flow testing). CEOE 2003b, Revised Table G-4 (well flow testing PM_{10} and H_2S).
Note(s):
a. Maximum emissions calculated assuming 8 hours/day and 20 days/month.
b. Fugitive Dust emissions include: erosion, delivery trucks, worker travel, and construction equipment. Erosion emissions are assumed to occur 24 hours/day, 30 days/month. All others are assumed to occur 8 hours/day, 20 days/month.
c. Maximum emissions do not occur in the same month. The sub-total presented is the highest hourly emissions occurring during any one month.
d. VOC emissions were originally based on benzene, toluene, and xylenes (BTX). Based on the applicant's revised VOC data the BTX totals were multiplied by 2.07 to include all VOC constituents.

Air Quality Table 11
SSU6 Project Estimated Maximum Daily Construction Emissions
For the Power Plant, Pipelines, and Transmission Lines, lb/day

Source	NO_x	CO	VOC	SO_x	PM_{10}	NH_3	H_2S
Construction Equipment [a]	211.4	158	30.6	3.9	11.9	---	---
Delivery Trucks [a]	85.51	25.27	6.61	0.78	2.82	---	---
Worker Travel [a]	60.94	714.48	77.75	0.46	1.62	---	---
Fugitive Dust [b]	---	---	---	---	114.0	---	---
Sub-Total [c]	327.8	866.2	107.1	4.8	128.9	---	---
Well Drilling	623.3	76.08	8.64	17.52	25.68	---	---
Well Flow Testing	---	---	11.1[f]	---	1,555	1,133	283.2
Total [c]	951	942	127	22.3	1,710	1,133	283.2

Source: CEOE 2002a. Detailed calculations located in Appendix G, Tables G-1 through G-1.6 (fugitive dust), G-2 (well drilling), G-3 to G-3.11 (construction equipment, worker travel, and delivery trucks), and G-4 (well flow testing). CEOE 2003b, Revised Table G-4 (well flow testing PM_{10} and H_2S).

Note(s):

a. Maximum emissions calculated assuming 8 hours/day and 20 days/month.

b. Fugitive Dust emissions include: erosion, delivery trucks, worker travel, and construction equipment. Erosion emissions are assumed to occur 24 hours/day, 30 days/month. All others are assumed to occur 8 hours/day, 20 days/month.

c. Maximum emissions do not occur in the same month. The sub-total presented is the highest hourly and daily emissions occurring during any one month.

d. Well Drilling maximum daily emissions are based on peak hourly emissions provided in Table 10, assuming 24 hours.

e. Well Flow Testing maximum daily emissions are based on hourly emissions provided in Revised Table G-4, assuming 24 hours. Maximum hourly emissions are for a single production well.

f. VOC emissions were originally based on benzene, toluene, and xylenes (BTX). Based on the applicant's revised VOC data the BTX totals were multiplied by 2.07 to include all VOC constituents.

Air Quality Table 12
SSU6 Project Estimated Maximum Annual Construction Emissions
For the Power Plant, Pipelines, and Transmission Lines, tons/year

Source	NO_x	CO	VOC	SO_x	PM_{10}	NH_3	H_2S
Construction Equipment	20.0	15.5	2.9	0.4	1.1	---	---
Delivery Trucks	7.13	2.107	0.551	0.07	0.23	---	---
Worker Travel	6.29	73.72	8.02	0.05	0.17	---	---
Fugitive Dust	---	---	---	---	13.13	---	---
Sub-Total	33.42	91.33	11.47	0.52	14.63	---	---
Well Drilling [a]	124.25	15.18	1.71	3.49	5.12	---	---
Well Flow Testing [b]	---	---	0.22 [c]	---	29.8	22.9	5.00
Total	158	107	13.4	4.0	49.6	22.9	5.00

Source: CEOE 2002a, Table 5.1-21 (total). Detailed calculations located in Appendix G, Tables G-1 through G-1.6 (fugitive dust), G-2 (well drilling), G-3 to G-3.11 (construction equipment, worker travel, and delivery trucks), and G-4 (well flow testing). CEOE 2003b, Revised Table G-4 (well flow testing PM_{10} and H_2S).

Note(s):

a. Well Drilling annual emissions are based upon 900 days of drilling and average fuel use (100% load equals 2284.8 gal/day – actual highest of three wells is 1012 gal/day or 44.3%).

b. Well flow testing based on only one well being flow tested at a time. Annual emissions from production wells are based on 768 hours for 10 wells. Annual emissions from injection wells are based upon 240 hours for 5 wells. Production wells - 96 hours per well (one well on each of Pads OB1-OB4). Production wells - 72 hours per well (one well on each of Pads OB1-OB4). Production wells - 48 hours per well (both wells on Pad OB-5).

c. VOC emissions were originally based on benzene, toluene, and xylenes (BTX). Based on the applicant's revised VOC data the BTX totals were multiplied by 2.07 to include all VOC constituents.

The construction vehicle emissions provided above were based on South Coast Air Quality Management District (SCAQMD) CEQA Handbook emission factors and load factors, and the estimated number of operational hours for each piece of equipment throughout project construction outlined in Appendices G-3 through G-3.5 of the AFC (CEOE 2002a). The emission estimates provided above do not include the potential emission reductions that may occur based on the application of tailpipe emission controls required in Condition of Certification **AQ-C3**, and use somewhat dated emission factors that may overestimate the potential equipment emissions. However, the emission estimates use an 8-hour per day, 20 day per month construction schedule that might underestimate maximum daily and annual emissions.

The construction emissions estimate for SSU6 is higher than the estimated construction emissions for most of the gas turbine power plant projects recently licensed or currently being evaluated by the CEC. This is mainly due to geothermal unique emissions sources, well flow testing, and the construction/drilling of the wells and well pads. In general, the onsite construction emission estimate is similar to those seen for medium to large gas turbine projects (i.e. 250 MW to 1000 MW gas turbine projects).

OPERATIONAL PHASE

Equipment Description

The major equipment proposed in the application includes the following:

- Geothermal Resource Production Facility (RPF) including ten geothermal fluid extraction (production) wells located on five well pads; brine and steam handling facilities from the production wellheads through the crystallizer/ clarifier system, to the injection wellheads; solids handling system; two brine ponds; seven brine injection wells on three well pads; two new injection wells on two existing pads, one dedicated to injection of cooling tower blowdown and the other to injection of aerated brine when accumulated in the brine pond; and steam polishing equipment designed to provide turbine-quality steam to the Power Generation Facility.
- Merchant class geothermal-powered Power Generation Facility (PGF) consisting of one geothermal power block. The PGF includes a condensing turbine/generator set, gas removal and pollutant abatement systems, and the heat rejection system.
- A 161 kV switchyard and several power distribution centers. Electricity generated by the SSU6 Project will be delivered to an existing Imperial Irrigation District (IID) electrical transmission line (L-Line), via the proposed 161 kV L-Line Interconnection, and ultimately connect to the existing El Centro and Avenue 58 substations located west of the project site.
- The PGF includes a 3,600-revolutions-per-minute (RPM) multi-casing, triple-pressure [High-Pressure (HP), Standard-Pressure (SP), and Low-Pressure (LP)], exhaust flow condensing turbine generator nominally rated at 200 megawatts (MW). The turbine is directly coupled to a totally enclosed water and air-cooled (TEWAC) synchronous type generator. The generator is expected to have a design rating of 235 megavolt amperes (MVA) at a power factor of 0.85 lagging. The turbine-generator unit will be fully equipped with all the necessary auxiliary systems for turbine control and speed protections, lubricating oil, glad sealing, generator excitation, and cooling.

- Cooling system consisting of two 10-cell counterflow cooling towers, equipped with 480-Volt fans. Each of the two cooling towers will be equipped with three 50 percent capacity, vertical, wet-pit circulating water pumps, and one 100 percent capacity, vertical, wet-pit auxiliary water pump.
- Common facilities include a control building, a service water pond, and other ancillary facilities.
- Standby diesel emergency generators including a 2 MW, 4,160-volt generator and a 300 kW, 480-volt generator. (2300 kW total)
- Fire protection system with three pumps: a 2,500-gpm motor driven fire pump; 2,500-gpm (290-Hp) diesel engine driven fire pump; and a 25-gpm jockey pump.

Equipment Operation

The power plant will be located on approximately 80 acres (Plant Site) of a 160-acre parcel within the unincorporated area of Imperial County, California. Two injection wells and two production wells will be located on the plant site, with the remaining eight production wells (four well pads) and seven injection wells (three well pads) located offsite. Nine geothermal power plants are within a 2-mile radius of the proposed plant site. Geothermal Power Plant Units 1, 2, 3, 4, and 5 lie to the southwest, while the Vulcan and Hoch Geothermal Power Plants lie to the southeast. The J.J. Elmore and Leathers geothermal power plants are to the northeast.

The project will be nominally rated at 200 MW (gross) and will produce 185 MW of on-line power.

Emission Controls

The proposed geothermal facility does not use combustion to generate electricity. Therefore, only minimal emissions of criteria pollutants, such as NO_x, CO, SO_2, and VOCs are expected from power production equipment. The applicant proposes to use best available control technology, management practices, and process monitoring equipment to minimize the air emissions from the proposed plant. The two criteria pollutants that would have the potential to cause significant impacts to air quality from normal plant operations, if uncontrolled, are PM_{10} and H_2S.

The cooling towers are the primary source of air emissions at the power plant during normal operations. These emissions include the introduced non-condensible gases (NCGs), offgassing from the condensate, and PM_{10} from liquid drift. NCGs, which flow from the flashing steam of the brine, collect in the condenser of the turbine generator, along with the condensate, where the NCGs are separated. The applicant has estimated that approximately 79% of the H_2S will be vented with the NCGs and approximately 21% will remain entrained in the condensate (District 2003b, page 13). Practically all of the benzene in the brine will be vented with the NCGs and no measurable benzene emissions will be entrained in the condensate (District 2003a, page 25).

The NCGs will be vented to a LO-CAT System. The LO-CAT System is a liquid reduction-oxidation process that uses a non-toxic iron catalyst to convert H_2S to elemental sulfur. The applicant is proposing a permitting control level for H_2S of 99.5

percent of the NCG gas emissions. The LO-CAT System will also reduce mercury emissions.

In addition to the LO-CAT System for H_2S abatement, the project will include a polishing system that uses a solid bed H_2S removal scavenger system (CEOE and CURE 2003). This system will ensure the reliability of the benzene abatement system by reducing the H_2S emissions saturating the carbon bed used to control benzene. The system will be imbedded in the LO-CAT System, between the LO-CAT and benzene abatement units. This system will utilize a proprietary carbon based media supplied by the equipment manufacturer. The system is expected to operate with two trains, each comprised of two vessels, operating in series, with one vessel in the lead position and the other in the lag position. When the H_2S levels at the outlet of the lead vessels equal the inlet level (meaning the proprietary media is completely spent), the lead vessels will be bypassed, leaving the lag vessels to treat the gas while the spent media is removed and replaced or recovered. The lag vessels will continue to operate until the media is completely spent, and then the process repeats.

After the H_2S emissions are reduced by the LO-CAT System and H_2S polishing system, the NCG stream will be vented through a carbon absorption unit to control brine benzene. This is the first time that carbon absorbers have been proposed for the control of benzene in a geothermal facility. Pilot testing conducted by CalEnergy at a Salton Sea power plant has shown that activated carbon will absorb 95 percent of the benzene in a NCG stream containing 40 to 70 parts per million (ppm) of benzene. The applicant is proposing a control level for benzene of 95 percent. Additionally, arsenic and other gaseous metal halides in the NCG stream are anticipated to be reduced by 90 percent collectively by the two systems (LO-CAT and benzene abatement systems). After the carbon absorbers, the NCGs are conveyed to the cooling tower cells (20 total) and released equally to each cell.

Some of the pollutants/impurities that collect in the condenser of the steam turbine generator separate into the water condensate stream, rather than separating into the NCG stream. These pollutants include H_2S and ammonia. As previously mentioned, the applicant estimated that approximately 20% of the H_2S would remain entrained in the condensate (District 2003a, page 14). When these condensates are collected they will be conveyed to a biofilter oxidizer cell to be installed at the condenser inlet end of each of the cooling towers (two total). The oxidizers operate as a liquid bioreactor and covert the H_2S in solution to sulfate (SO_4) in the condensate. In practice, these oxidizers have reduced H_2S concentration levels down to nondetectable levels in the cooling tower exhaust. The applicant is proposing a H_2S control level of 90 percent for the project's biofilter oxidizers (CEOE 2003b, Response #3d). After the oxidizer, the condensate is routed through the cooling towers where the remaining gaseous phase pollutants/impurities are stripped/offgassed. The applicant provided source test results from the Leather's plant biofilter oxidizer, which showed an H_2S control efficiency of greater than 98% (CEOE 2003c).Ammonia, an impurity in the brine, flashes with the high, standard, and low pressure steam and is then re-condensed into the condensate stream. Ammonia's high affinity with water keeps almost all of the ammonia in the condensate stream, with only a very small fraction ending up in the NCG stream. The condensate stream eventually ends up in the cooling tower where the majority of the ammonia emissions are stripped/offgassed into the cooling tower exhaust. The applicant and staff have investigated potential controls for the ammonia emissions from the cooling towers, but have not found any technically feasible and cost effective measures for ammonia emissions control. Additionally, some of the flashed ammonia remains in the steam that is used in and then exhausted from the dilution water heaters.

The cooling towers use the condensate for cooling tower makeup. Substances present in the condensate can be contained in the drift of the cooling tower. The cooling tower emissions will be controlled by maintaining the TDS concentration in the circulating water and by using drift eliminators with an efficiency of 0.0005 percent (CEOE 2002b, Data Request Response #5).

The turbine bypass provides the ability to divert high-pressure steam, which contains almost all of the H_2S produced by the geothermal resource (greater than 90 percent), from the turbine inlet directly into the condenser to reduce H_2S emissions to an acceptable level in the event of a plant trip during operations. HP, SP and LP steam will be combined and diverted to four 80-foot vent relief tanks and released to the atmosphere. The proposed bypass will be equipped with a motor-actuated isolation valve that is closed during normal operation. Condensed steam from the turbine condenser will be routed through the hotwell pumps to the plant condensate distribution system. As steam condenses, NCGs will continue to be routed to the LO-CAT and benzene systems for H_2S and benzene abatement.

Since maintaining vacuum conditions is preferred in the main condenser during turbine bypass operation to limit stress on the plant systems, NCGs are routed to the LO-CAT system through the vacuum pumps, air ejectors and intercondensers. In the event that standby electrical power is limited, a bypass around the vacuum pump will be installed. In this mode of operation, condenser pressure will increase to 2 pounds-per-square-inch (psig), providing sufficient pressure to move the NCG through the air ejectors, intercondensers and to the abatement plant. Motive steam to the air ejectors will be secured in this configuration. Auxiliary cooling pumps, intercondensers, a condensate pump, two circulating water pumps and cooling tower fans will remain in service to condense the steam and cool the NCG below 130°F, suitable for processing in the LO-CAT and benzene abatement systems.

The operation of the turbine bypass system is dependent on the availability of electrical power and the operation of certain plant equipment. Depending on the particular circumstances triggering an upset condition, a total loss of power or equipment failure may prevent operation of the turbine bypass. To provide a safe method of relieving the high-pressure steam during upset conditions, the plant will be equipped with two high-pressure atmospheric flash tanks. Temporary emissions may occur for a short period of time at the high-pressure steam vents until the turbine bypass system can be placed in service or until steam generation can be secured or stopped (CEOE 2002a, page 3-22).

Particulate emissions from the filter cake handling equipment will be controlled by minimizing handling and keeping the filter cakes covered.

Project Normal Operating Emissions

Air emissions will be generated from operating the major project components. **AIR QUALITY Tables 13 through 15** summarize the maximum (worst-case) estimated levels of the different criteria pollutants associated with project operation. The assumptions used in calculating the emissions in these tables include:

- usage factors based on operating experience
- emission factors guaranteed by the manufacturer,
- emission from engines based on 100 hours of operation per year, and the engines will not be tested at the same time, or on the same day,
- facility base-loaded operation of 24 hours per day, 365 days per year, for a total of 8,760 hours per year, and
- emissions based on the maximum design flow rate of geothermal brine during summer time conditions to generate 175 MW. In the wintertime, approximately 185 MW can be generated at this design flow rate. Base-load operations are not expected to be below 175 MW.
- The cooling tower and dilution water heater emissions are based on mass balance calculations using estimated stream flow rates and expected pollutant concentrations.

The proposed project's hourly emissions of criteria air pollutants are shown in **AIR QUALITY Table 13**.

AIR QUALITY Table 13
SSU6 Project Maximum Hourly Emissions, lb/hr

Operational Source	NO_x	CO	VOC	SO_x	PM_{10}	NH_3	H_2S
Cooling Tower – NCG [a]	---	---	0.375	---	---	0.12	0.766
Cooling Tower – Offgassing	---	---	---	---	---	712	3.374
Cooling Tower – Drift	---	---	---	---	2.91	0.0008	---
Dilution Water Heater	---	---	---	---	0.14	16.54	0.678
Filter Cake Silica	---	---	---	---	0.0064	---	---
Filter Cake Sulfur	---	---	---	---	4.4E-5	---	---
EG-480 Engine [b]	---	---	---	---	---	---	---
EG-4160 Engine [b]	34.24	2.19	0.82	1.15	0.65	---	---
Fire Pump Engine [b]	---	---	---	---	---	---	---
Operation & Maintenance (O&M) Equipment	5.49	29.55	1.70	0.27	0.06	---	---
O&M Fugitive Dust	---	---	---	---	0.074	---	---
Total Maximum Hourly Emissions (lb/hr)	39.73	31.74	2.52	1.42	3.84	728.7	4.82

Sources: CEOE 2002a, Tables 5.1-23 through 5.1-31. Detailed calculations located in Appendix G, Tables G-6 through G-13. CEOE 2002b, Data Request Response #5 and Attachment AQ-5 (Revised Tables 5.1-25, 5.1-26, 5.1-32, G-7, G-8, and G-13). CEOE 2003a, Data Request Response #113. CEOE 2003b.
Note(s):
a. Non-condensible gases
b. The engines will not be tested at the same time, or on the same day.

AIR QUALITY Tables 14 and 15 summarizes the maximum (worst case) daily and annual average estimated criteria pollutants emissions from the project, using the operating emissions assumptions provided above.

AIR QUALITY Table 14
SSU6 Project Estimated Maximum Daily Emissions, lb/day

Operational Source	NO_x	CO	VOC	SO_2	PM_{10}	NH_3	H_2S
Cooling Tower – NCG	---	---	9.01	---	---	2.88	18.38
Cooling Tower – Offgassing	---	---	---	---	---	17,088	80.98
Cooling Tower – Drift	---	---	---	---	69.8	---	---
Dilution Water Heater	---	---	---	---	3.26	396.96	16.27
Filter Cake Silica	---	---	---	---	0.0512	---	---
Filter Cake Sulfur	---	---	---	---	0.00107	---	---
EG-480 Engine	---	---	---	---	---	---	---
EG-4160 Engine [a]	34.24	2.19	0.82	1.15	0.65	---	---
Fire Pump Engine	---	---	---	---	---	---	---
Operation & Maintenance (O&M) Equipment	43.90	236.41	13.58	2.18	0.5024	---	---
O&M Fugitive Dust	---	---	---	---	1.78	---	---
Total Maximum Daily Emissions	79.14	238.60	23.41	3.33	76.04	17,488	115.63

Sources: CEOE 2002a, Tables 5.1-23 through 5.1-31. Detailed calculations located in Appendix G, Tables G-6 through G-13. CEOE 2002b, Data Request Response #5 and Attachment AQ-5 (Revised Tables 5.1-25, 5.1-26, 5.1-32, G-7, G-8, and G-13). CEOE 2003a, Data Request Response #113 (VOCs).

Note(s):
a. Only one engine is tested for a maximum of 1 hour per day.

AIR QUALITY Table 15
SSU6 Project Estimated Maximum Annual Average Emissions, tons/year

Operational Source	NO_x	CO	VOC	SO_2	PM_{10}	NH_3	H_2S
Cooling Tower – NCG	---	---	1.64	---	---	0.526	3.36
Cooling Tower – Offgassing [a]	---	---	---	---	---	2,681	14.78
Cooling Tower – Drift	---	---	---	---	12.74	0.0035	---
Dilution Water Heater	---	---	---	---	0.59	72.45	2.97
Filter Cake Silica [b]	---	---	---	---	0.0014	---	---
Filter Cake Sulfur [b]	---	---	---	---	2.92E-05	---	---
EG-480 Engine [c]	0.2	0.01	0.002	0.01	0.001	---	---
EG-4160 Engine [c]	1.7	0.11	0.04	0.06	0.03	---	---
Fire Pump Engine [c]	0.2	0.01	0.003	0.01	0.002	---	---
Operation & Maintenance (O&M) Equipment	1.6	10.13	0.55	0.35	0.0232	---	---
O&M Fugitive Dust	---	---	---	---	0.321	---	---
Total Average Annual Emissions (tpy)	3.7	10.24	2.24	0.43	13.71	2,754	21.11

Sources: CEOE 2002a, Tables 5.1-23 through 5.1-31. Detailed calculations located in Appendix G, Tables G-6 through G-13. CEOE 2002b, Data Request Response #5 and Attachment AQ-5 (Revised Tables 5.1-25, 5.1-26, 5.1-32, G-7, G-8, and G-13). CEOE 2003a, Data Request Response #113 (VOCs).

Note(s):
a. Cooling tower offgassing gas annual ammonia emissions are based upon an annual average of 612 lbs/hr at 183 MW (CEOE 2002b, DR#1).
b. Annual average emissions for filter cake silica and sulfur are based on 0.00768 lbs/day and 0.00016 lbs/day, respectively.
c. Engine annual emissions based on 100 hours of operation.

Project Potential Temporary Operating Emissions

Well rework/new well drilling, well flow activities, steam vent tanks, and plant startup emission sources are not routine, but are expected to occur from time to time. Based on past experience at the existing Salton Sea Units, the applicant has estimated the duration, frequency, and emissions for these sources.

Over time, the existing wells may experience issues with capacity and pressure drop. Normally these are not issues associated with the geothermal reservoir, but with the specific conditions around a well. The applicant anticipates the following rework schedule:

- Production Wells. A coil tubing clean-out of each production well (10 total) is scheduled every two to six years, with an average of four years. This involves two 2-ton trucks (one water truck, one nitrogen truck). Duration of work is three days.
- Production Wells. Re-drill of a production well (10 total) is typically scheduled every seven to 17 years, with an average of 12 years. Re-drilling one well per year is anticipated. Duration of work is 21 days.
- Injection Wells. Re-drill of an injection well (seven total) is planned every two to four years. Re-drilling one to two wells per year is anticipated. Duration of work is 10 days. New pipe is installed in the well.
- Plant Well. A re-drill is scheduled every four years (one well). Duration of work is eight days.
- Condensate Well. A re-drill is scheduled every four years (one well). Duration of work is 10 days.
- The emission estimates for well rework drilling are based on typical drill rig horsepower, drilling schedule and Caterpillar engine emission factors. The well flow and steam vent tank emissions are based on mass balance calculations using estimated stream flow rates and estimated stream pollutant concentrations.

AIR QUALITY Table 16 shows the emissions estimated for temporary well rework/new well drilling emissions.

Air Quality Table 16
SSU6 Project Estimated Well Rework/New Well Drilling Emissions

	NO_x	CO	VOC	SO_x	PM_{10}
Pounds Per Hour Per Well	25.97	3.17	0.36	0.73	1.07
Annual Emissions (tpy)	6.90	0.84	0.09	0.19	0.285

Source: CEOE 2002a, Table 5.1-33. Detailed calculations located in Appendix G, Table G-2.
Note(s):
a. NO_2, CO, VOC and PM_{10} emission factors based on Caterpillar documented emission data for 3412DITTA Engines, SO_2 based on 0.05% Sulfur fuel. Engine Hp based upon typical drill rig used in the Salton Sea area.
b. Long term emissions are based upon 50 days per year of drilling (vs. 900 days for construction) and average fuel use.

Well flow activities include warming up a production well, which are warmed up following clean-out or re-drill activities or before a plant startup. The applicant anticipates that each of the 10 production wells will be shut down for operational reasons twice per year. A warm up is required for each shutdown. In a year with no coil tubing clean-outs or redrills, the flow activities are estimated to be approximately 40 hours per year. Coil tubing clean-outs require an additional 48 hours per well. Three coil clean-outs are anticipated per year. The re-drilling of a production well will also require a flow run of about 48 hours. Only one re-drilling of a production well is anticipated per year. The re-drilling of an injection well requires a flow run of approximately 18 hours. Re-drilling of three injection wells is anticipated each year. The applicant has identified that flow testing is not required for the onsite plant injection wells. **AIR QUALITY Table 17** provides the potential emissions for well flow activities.

Air Quality Table 17
SSU6 Project Estimated Well Flow Run Emissions [a]

	VOC [d]	PM_{10}	NH_3	H_2S
Production Well (lb/hr)	0.47	64.8	47.2	11.8
Injection Well (lb/hr)	0.39	41.0	39.3	3.9
Annual Emissions (tpy)[b,c]	0.06	8.6	6.5	1.5

Source: CEOE 2002a, Table 5.1-34. Detailed calculations located in Appendix G, Table G-14. CEOE 2002c, Data Response #100 and Revised Table G-14. CEOE 2003b, Revised Table G-14 (PM_{10} and H_2S).
Note(s):
a. A well could be venting for a total of 48 hours. Only one well will be flow tested at a time.
b. Annual emissions from production wells are based on 232 hours [40 hours for warm ups, 144 hours for three coil tubing clean-outs (48 hr/each), and 48 hours for re-drilling one production well].
c. Annual emissions from injection wells are based on 54 hours for re-drilling three injection wells (18 hr/each).
d. VOC emissions were originally based on benzene, toluene, and xylenes (BTX). Based on the applicant's revised VOC data the BTX totals were multiplied by 2.07 to include all VOC constituents.

In situations where there is a turbine trip and the turbine cannot receive the steam generated, the excess steam is routed to a turbine bypass and to the vent relief tanks. This system is also used for cold and warm plant startups and shutdowns. The applicant expects a trip to occur six times a year and last for less than two hours. **AIR QUALITY Table 18** provides the potential emissions for vent relief tanks during turbine bypass.

Air Quality Table 18
SSU6 Project Estimated Vent Relief Tank Emissions During Venting

	VOC [b]	PM_{10}	NH_3	H_2S
Vent Relief Tanks (total lbs/hr)	0.50	2.87	86.0	17.7
Cooling Tower (lbs/hr)	0.25	2.92	546	3.75
Dilution Water Heater (lbs/hr)	0	0.136	16.5	0.678
Annual Emissions (tpy)	0.019	0.148	16.2	0.553

Source: CEOE 2002a, Table 5.1-35. Detailed calculations located in Appendix G, Table G-15. CEOE 2003b, Revised Table G-15 (PM_{10} and H_2S).
Note(s):
a. Annual emissions assume 50 hours at 100 percent load.
b. VOC emissions were originally based on benzene, toluene, and xylenes (BTX). Based on the applicant's revised VOC data the BTX totals were multiplied by 2.07 to include all VOC constituents.

The applicant anticipates one cold plant startup per year. **AIR QUALITY Table 19** provides the estimated emissions for plant startup.

Air Quality Table 19
SSU6 Project Estimated Startup Emissions

	VOC [e]	PM_{10}	NH_3	H_2S
Production Test Unit (lbs/hr) [a]	0.47	64.8	47.2	11.8
100% Vent Relief Tanks (total lbs/hr) [b]	0.50	2.87	86.0	17.7
100% Cooling Tower (lbs/hr) [c]	0.25	2.92	546	4.14
100% Dilution Water Heaters (lbs/hr) [c]	0	0.136	16.54	0.678
Annual Emissions (tpy) [d]	0.0088	1.48	5.14	0.305

Source: CEOE 2002a, Table 5.1-36. Detailed calculations located in Appendix G, Table G-16. CEOE 2002c, Data Request Response #101. CEOE 2003b, Revised Tables G-16 (PM_{10} and H_2S).
Note(s):
a. A total of 45 hours will be venting at Production Test Unit emissions rates (0.8 million lbs/hr steam)
b. A total of 5 hours at 7% of full flow will be venting at the vent relief tanks (VRTs)
c. A total of 5 hours at 2.52 times full flow (per the facility startup schedule presented in Revised Table G-5.1) will be venting at Cooling Towers and Dilution Water Heaters.
d. A period is one startup per year.
e. VOC emissions were originally based on benzene, toluene, and xylenes (BTX). Based on the applicant's revised VOC data the BTX totals were multiplied by 2.07 to include all VOC constituents.

INITIAL COMMISSIONING

The initial commissioning of a power plant refers to the time frame between the completion of the construction and the consistent production of electricity for sale on the market. For most power plants, operating emission limits usually do not apply during the initial commissioning procedures.

The range of commissioning activities for the SSU6 geothermal power plant include the following: 1) well warm-up; 2) production line warm-up; 3) preheat RPF vessels; 4) steam blow; 5) turbine preheat; 6) various load tests; and 7) turbine performance test. An estimate of the hours required for each of these activities has been assessed.

During commissioning, the brine flow from a production well would be routed to the production test unit (PTU) for well warm-up (approx. 18 hours). Afterwards, the brine flow would be routed to the main production line allowing it to flow through the plant. Generated steam would be routed to the vent relief tanks (VRTs) and combined (CEOE 2003b, Response #3b). In addition to warming up the production line, the brine and steam would preheat the RPF vessels. These activities would occur for approximately six hours. The vent relief tanks, however, would continue to vent steam throughout the remainder of the commissioning period. The remaining production wells (eight) would then be routed to the PTU (18 hours each) for well warm-up. Again, the brine flow would be routed to the main production line, where the brine flows through the plant and the steam vents to the vent relief tanks. Once all nine wells are flowing, steam would be routed through selected steam pipelines up to the turbine and vented through temporary openings (i.e. steam blows). After a run of approximately 12 hours at each of the six steam lines, the turbine preheat and other various tests would occur. Once the testing is completed, a performance test would be conducted for the turbine under various loads. To bring the power plant online, a total of 14 to 15 days or 354 hours of commissioning activities are anticipated. Plant commissioning activities and air pollutant emissions expected from plant commissioning are summarized in **AIR QUALITY Tables 20 and 21**, respectively.

AIR QUALITY TABLE 20
Estimated Power Plant Commissioning Schedule[a]

Commissioning Activities Task	Event Duration	Emission Location	Emission Rate	
			VRT A/B Rate	VRT C/D Rate
No. 1 Well Warm-up	18 hours	Production Test Unit	PTU (Well Startup)	PTU (Well Startup)
No. 1 Production Line Warm-up	6 hours	VRTs	3.5% of VRTs (total)	0
Preheat RPF Vessels	12 hours	VRTs	3.5% of VRTs (total)	0
No. 2 Well Warm-up	18 hours	Production Test Unit	PTU (Well Startup)	PTU (Well Startup)
No. 2 Production Line Warm-up	18 hours	VRTs	7.0% of VRTs (total)	0
No. 3 Well Warm-up	18 hours	Production Test Unit	PTU (Well Startup)	PTU (Well Startup)
No. 3 Production Line Warm-up	18 hours	VRTs	10.5% of VRTs (total)	0
No. 4 Well Warm-up	18 hours	Production Test Unit	PTU (Well Startup)	PTU (Well Startup)
No. 4 Production Line Warm-up	18 hours	VRTs	14% of VRTs (total)	0
No. 5 Well Warm-up	18 hours	Production Test Unit	PTU (Well Startup)	PTU (Well Startup)
No. 5 Production Line Warm-up	18 hours	VRTs	17.5% of VRTs (total)	0
No. 6 Well Warm-up	18 hours	Production Test Unit	PTU (Well Startup)	PTU (Well Startup)
No. 6 Production Line Warm-up	18 hours	VRTs	17.5% of VRTs (total)	3.5% VRTs (total)
No. 7 Well Warm-up	18 hours	Production Test Unit	PTU (Well Startup)	PTU (Well Startup)
No. 7 Production Line Warm-up	18 hours	VRTs	17.5% of VRTs (total)	7% VRTs (total)
No. 8 Well Warm-up	18 hours	Production Test Unit	PTU (Well Startup)	PTU (Well Startup)
No. 8 Production Line Warm-up	18 hours	VRTs	17.5% of VRTs (total)	10.5% VRTs (total)
No. 9 Well Warm-up	18 hours	Production Test Unit	PTU (Well Startup)	PTU (Well Startup)
No. 9 Production Line Warm-up	6 hours	VRTs	15.75% of VRTs (total)	15.75% of VRTs (total)
HP Steam Blow (First Line –Train 1)	12 hours	HP Steam Blow Stack, VRTs	Steam Blow Stack 15.75% of Vent Tanks (SP, LP)	Steam Blow Stack 15.75% of Vent Tanks (HP, SP, LP)
HP Steam Blow (Second Line – Train 2)	12 hours	HP Steam Blow Stack, VRTs	Steam Blow Stack 15.75% of Vent Tanks (HP, SP, LP)	Steam Blow Stack 15.75% of Vent Tanks (SP, LP)
SP Steam Blow (First Line – Train 1)	12 hours	SP Steam Blow Stack, VRTs	Steam Blow Stack 15.75% of Vent Tanks (HP, LP)	Steam Blow Stack 15.75% of Vent Tanks (HP, SP, LP)
SP Steam Blow (Second Line – Train 2)	12 hours	SP Steam Blow Stack, VRTs	Steam Blow Stack 15.75% of Vent Tanks (HP, SP, LP)	Steam Blow Stack 15.75% of Vent Tanks (HP, LP)
LP Steam Blow (First Line – Train 1)	12 hours	LP Steam Blow Stack, VRTs	Steam Blow Stack 15.75% of Vent Tanks (HP, SP)	Steam Blow Stack 15.75% of Vent Tanks (HP, SP, LP)
LP Steam Blow (Second Line – Train 2)	12 hours	LP Steam Blow Stack, VRTs	Steam Blow Stack 15.75% of Vent Tanks (HP, SP, LP)	Steam Blow Stack 15.75% of Vent Tanks (HP, SP)
Turbine Preheat, Vacuum Test, and Other Tests	96 hours	Cooling Towers	Steam Blow Stack 15.75% of Vent Tanks (HP, SP, LP)	Steam Blow Stack 15.75% of Vent Tanks (HP, SP, LP)
Turbine Load Test, Etc.	18 hours	Cooling Towers	Steam Blow Stack 15.75% of Vent Tanks (HP, SP, LP)	Steam Blow Stack 15.75% of Vent Tanks (HP, SP, LP)
Turbine Performance Test	48 hours	Normal Operating Condition Emissions		

Source: CEOE 2003b, Revised Table G-5.1.
Note(s):
a. Times are approximate and subject to change when a more definitive startup program is developed. Some activities are scheduled to occur simultaneously, specifically the production line warmup for a brine well (emissions through the VRT exhausts) normally occurs simultaneously with the well warmup (emissions through the PTU unit exhaust) for the next brine well that is being brought online.

AIR QUALITY TABLE 21
Estimated Power Plant Commissioning Emissions

Source	Emissions Rate	Hours per Period	VOC [a] (lb/hr)	PM_{10} (lb/hr)	H_2S (lb/hr)	NH_3 (lb/hr)
PTU	100%	162	0.46	64.8	11.8	47.2
Vent Relief Tanks (total)	100%	71.82	7.40	6.83	190	786
Dilution Water Heaters	100%	143.6	0	0.136	0.68	16.5
Cooling Tower	100%	71.82	0.38	2.92	4.14	712
Steamblow [b]	31.5% of full VRT rates	72	0.78	0.717	19.99	82.53
Total (tons/period)	---	---	0.34	5.63	8.7	61.8

Sources: CEOE 2002a, Tables G-5 through G-5.6. CEOE 2002c, DR #99 and Revised Table G-5. CEOE 2003b, Revised Table G-5.
Note(s):
a. VOC emissions were originally based on benzene, toluene, and xylenes (BTX). Based on the applicant's revised VOC data the BTX totals were multiplied by 2.07 to include all VOC constituents.
b. Steamblow emissions (lb/hr) are estimated based on the lbs/period divided 72 hours.

The emissions shown in **AIR QUALITY Table 21** were determined through mass balance, using expected flow rates and expected pollutant concentrations. The emissions estimated here are subject to change based on the actual brine constituent concentrations.

PROJECT IMPACTS

MODELING APPROACH

The applicant's approach to the SSU6 Project consists of three major components affecting air quality, including: (1) Well field (well pads, production wells, injection wells, associated pipelines), (2) power plant, and (3) transmission line. Additionally, well field and power plant emissions have been divided into three areas including: (1) construction, (2) operations, and (3) temporary emissions. The construction emissions are from those activities associated with building the entire facility, including the commissioning period. The operations emissions are based on peak emissions associated with maximum design flow rates of brine through the facility. The temporary emissions are those associated with anticipated intermittent emissions from devices or processes that may occur, such as reworking wells and steam being sent to the vent relief tanks during an upset condition, following the commencement of power plant operations.

The applicant performed an air dispersion modeling analysis to evaluate the project's potential impacts on the existing ambient air pollutant levels during construction, operation, and potential temporary activities. Air dispersion modeling provides estimates of the ground level concentrations of the pollutants emitted by the proposed project. Staff reviewed the applicant's modeling analysis and determined that the modeling performed was generally adequate, but in some cases the modeling assumptions and methodologies employed were too conservative. In other cases, the applicant's modeling results show high impacts without any description of potential mitigation techniques. Therefore, staff has performed its own construction and operations modeling analyses, where appropriate, and is presenting the applicant's modeling analyses and staff's revised modeling analyses.

The applicant used the USEPA-approved ISCST3 model to estimate the worst-case impacts of the project's estimated NO_x, PM_{10}, CO, SO_x, and H_2S emissions resulting from project construction, normal operation, and temporary operation activities. The ISC model is a steady-state Gaussian plume model, appropriate for regulatory use that can be used to assess pollution concentrations from a wide variety of emission sources. Modeled impacts were added to the available ambient background concentrations. A summary of the monitoring data is provided in the **Setting** section.

Staff compared the results of the modeling analysis with the ambient air quality standards for each respective air contaminant to determine whether the project's emission impacts would cause a new violation of the ambient air quality standards or significantly contribute to an existing violation.

Inputs for the modeling include stack information (exhaust flow rate, temperature, and stack dimensions), emission data and meteorological data, such as wind speed, atmospheric conditions, and site elevation. For this project, the meteorological data used as inputs to the model included hourly wind speeds and directions measured at the Imperial County Airport Station for the years 1995 to 1999. Upper air data for the same time period were taken from Tucson, Arizona. Staff found a few problems with how the meteorological data was processed. Missing wind speed data was routinely processed as calm, which is not the best method for filling missing wind speed data and could impact the modeling results. Also, processed data does not match the raw data and appears to have been offset by an hour or two. This problem seems to be occurring as a result of the use of the USEPA recommended meteorological processing program PCRAMMET. Staff has seen this problem occur previously in another siting case when a similar raw meteorological data set was processed using PCRAMMET without proper pre-processing. However, this should not significantly affect the modeling results.

CONSTRUCTION IMPACTS

The applicant modeled the emissions from construction activities including: (1) fugitive dust emissions, (2) well drilling combustion emissions, (3) construction equipment exhaust emissions, (4) well flow testing, and (5) plant commissioning. This analysis was completed using the ISCST3 model (Version 00101 and 02035). The following modeling scenarios and assumptions were assumed to assess the impacts to ambient air quality standards (CEOE 2002a, p. 5.1-24 to 26; and CEOE 2003b CD modeling files):

- The first four activities were assumed to occur during the same time period.
- Short-term (1-hour, 3-hour, 8-hour, and 24-hour) combined worst-case construction pollutant emission modeling was performed based on the worst-case construction month. Based on the assumed construction schedule, type of construction activity and equipment use, the worst-case emissions for PM_{10} occurs in month 18, for both NO_2 and SO_2 occurs in month 15, and for CO occurs in month 16.
- Fugitive dust (PM_{10}) was modeled as two area sources (wind erosion and equipment generated) covering the project site (Release Height=2.0 meters).

- Well drilling (PM_{10}, NO_2, SO_2, CO) was modeled as equivalent point sources with three rigs operating at the same time for the 24-hour averaging period. The three rig locations causing the highest collective concentrations were used in the evaluation. For the annual period a total of 15 wells were assumed with the same stack parameters (H=14 feet, T=855°F, D=1.33 feet, V=112 feet/second, where H=height, T=temperature, D=diameter, V=velocity).
- Construction equipment exhaust (PM_{10}, NO_2, SO_2, CO) was modeled as four equivalent point sources uniformly emitting the equipment exhaust emissions (H=12 feet, T=850°F, D=0.49 feet, V=298 fps).
- Well flow testing (PM_{10} and H_2S) was modeled as six point sources (Production Flow Run: One source with H=50 feet, T=226.7°F, D=9 feet, V=40 fps. Injection Flow Run: Five sources with H=37.92 feet, T=226.7°F, D=6 feet, V=48.7 fps).
- Well flow testing for H_2S modeling was later revised based on flow testing at a reduced flow rate at three well pads and the production test unit operating. The PM_{10} modeling was also revised in this fashion; however, those modeling results are not included as the maximum impacts cannot be determined as the revised modeling analysis does not also include the construction equipment and fugitive dust emission sources.

AIR QUALITY Table 22 provides the results of the applicant modeling analyses for onsite facilities construction, well drilling, and well flow construction impacts.

AIR QUALITY Table 22
Applicant Construction Modeling Results

Pollutant	Averaging Period	Project Impact (σg/m^3)	Background Concentration (σg/m^3) [a]	Total Impact (σg/m^3)	Limiting Standard (σg/m^3)	Type of Standard	Percent of Standard (%)
NO_2 [b]	1-Hour	268	180	448	470	CAAQS	95
	Annual	5.2	19	24.2	100	NAAQS	24
PM_{10}	24-Hour	72	115	**187**	50	CAAQS	**374**
	Annual Geo. Mean	15	38.6	**53.6**	30	CAAQS	**179**
CO	1-Hour	193	8,000	8,193	23,000	CAAQS	36
	8-Hour	111	4,000	4,111	10,000	CAAQS	41
SO_2	1-Hour	19	73	92	655	CAAQS	14
	3-Hour	12	63	75	1,300	NAAQS	6
	24-Hour	5.5	47	52.5	105	CAAQS	50
	Annual	0.2	5	5.2	80	NAAQS	7
H_2S	1-Hour	16.2	24.6	40.8	42	CAAQS	97

Source: CEOE 2002a. AFC Tables 5.1-54 (NO_2), 5.1-62 (CO),and 5.1-73 (SO_2). CEOE 2003b. Attachment AQ4 – PSA Revised Modeling Table 5.1-47 (H_2S).
Note(s):
a. Background concentration values for this table and all other modeling result tables have been adjusted to the staff recommended values shown in **AIR QUALITY Table 9**.
b. The ozone limiting method (ISC3OLM) was used for 1-hour NO_2 concentrations. The ambient ratio method (factor 0.75) for rural areas was used for annual NO_2 concentrations.

As can be seen from the modeling results provided in **AIR QUALITY Table 22**, with the exception of 24-hour and annual PM_{10} impacts, construction impacts are below the state and national standards. It should be noted that the state 24-hour and annual PM_{10} standards are exceeded in the absence of construction emissions from the SSU6 Project. Based on the applicant's modeling results, the activities resulting in fugitive dust emissions exceed the 24-hour California PM_{10} standard by a factor of 1.4 (72/50=1.44). The applicant has assumed an 80 percent control level based on USEPA reference levels being applied to the proposed fugitive dust mitigation plan.

Staff reviewed the applicant's modeling results and found that the modeling techniques and assumptions may over predict impacts from the fugitive dust emission sources and may under predict impacts from the equipment tailpipe PM_{10} emission sources. Some of these assumptions and techniques used by the applicant are as follows:

1. The fugitive dust emissions were modeled as area sources.
2. Unpaved road emissions from site access and egress were assumed to occur for 1.73 miles per vehicle and those emissions were included in the onsite fugitive dust area source.
3. The equipment emissions were modeled as only four point sources with extremely high exit velocities.

Staff remodeled the construction PM_{10} emissions by: 1) using volume sources distributed within the construction site to model the fugitive dust emissions; 2) Assuming that the access roads are paved at the beginning of construction (required under staff condition of certification AQ-C3) to eliminate the large quantity of unpaved road emissions and by not including the offsite paved road emissions as part of the onsite construction emissions; 3) using additional point sources with lower exhaust velocities to model the equipment exhaust emissions. Staff further remodeled the injection well testing stack from 38 feet to 80 feet as a mitigation measure. Staff did not update this modeling to reflect the applicant's revised well pad construction modeling assumptions, as the applicant's revised well testing results were similar in magnitude to staff's modeling results for well testing. The results of staff's construction modeling analysis are provided in **AIR QUALITY Table 23**.

AIR QUALITY Table 23
Staff Construction Modeling Results

Pollutant	Averaging Period	Project Impact ($\sigma g/m^3$)	Background Concentration ($\sigma g/m^3$) [a]	Total Impact ($\sigma g/m^3$)	Limiting Standard ($\sigma g/m^3$)	Type of Standard	Percent of Standard (%)
PM_{10}	24-Hour	39	115	**154**	50	CAAQS	**308**
	Annual Geo. Mean	4.7	38.6	**53.3**	30	CAAQS	**178**

The peak 24-hour PM_{10} modeling results show that the highest modeled impacts occur approximately two-thirds of a mile from the center of the project site at elevated terrain within the Obsidian Butte area and that they are primarily due to the injection well flow emissions. The highest impacts from the construction equipment and construction fugitive dust sources occur at the project fence line and decrease rapidly with distance.

The maximum 24-hour and annual PM_{10} impacts from project construction modeled to the approximate center of the City of Calipatria are 3.41 ug/m^3 and 0.06 ug/m^3, respectively,.

Staff has proposed mitigation measures to mitigate onsite construction PM_{10} impacts and will suggest mitigation measures to mitigate the well drilling and well flow impacts.

OPERATION IMPACTS

The applicant modeled the emissions from operating activities including: (1) fugitive dust emissions from filter cake handling and operating/maintenance equipment, (2) NCGs from the cooling towers, (3) offgassing at the cooling towers, (4) drift from the cooling towers, (5) dilution water heaters, (6) emergency generators and fire pump, and (7) operating/maintenance exhaust equipment. This analysis was completed using the ISCST3 model (Version 00101 and 02035). The following modeling scenarios and assumptions were assumed to assess the impacts to ambient air quality standards (CEOE 2002a, p. 5.1-27 to 30):

- Filter cake handling activities (PM_{10}) were modeled as three volume sources (Silica and Sulfur Filter Cake Handing: two sources and one source, respectively, with Release Height=12 feet).
- Operations and maintenance equipment on paved and unpaved roads (PM_{10} fugitive dust only) were modeled as ten area sources (Paved and Unpaved Roads: three sources and six sources, respectively, with Release Height=2 meters).
- Drift from the cooling towers (PM_{10} and H_2S) was modeled as twenty point sources - one for each cell (H=58 feet, D=32 feet, V=33 fps). Stack temperatures vary by season and by brine throughput at the brine handling facilities (T_{summer}=96.1°F, $T_{annual\ avg}$=80.4°F, T_{winter}=72.6°F).
- Exhaust from dilution water heaters (PM_{10}, H_2S) was modeled as two point sources (H=45 feet, T=213.1°F, D=8 feet). Stack velocities vary by season and by brine throughput (V_{summer}=31.9 fps, $V_{annual\ avg}$=30.5 fps, V_{winter}=30.2 fps).
- Emergency generators and fire pump (PM_{10}, NO_2, SO_2, CO) were modeled as point sources (Emergency Generator 480: H=40 feet, T=793°F, D=0.67 feet, V=128 fps, Emergency Generator 4160: H=60 feet, T=963°F, D=1.5 feet, V=160 fps, Fire Pump: H=40 feet, T=855°F, D=0.5 feet, V=128 fps).
- Operations and maintenance equipment (PM_{10}, NO_2, SO_2, and CO exhaust emissions) was modeled as seventeen point sources. Five point sources were used to characterize the truck that transfers trailers from the filter cake handling area to the trailer storage area, and twelve point sources were used to characterize the other equipment operating in the main power plant area (H=12 feet, T=850°F, D=0.333 feet, V=298 fps).
- Stored filter cake (radon) was modeled as an area source (Release Height=12 feet, Area=2.38acres) to determine the health risk impact to the nearest resident location under normal operating conditions. The nearest resident is located at the Sonny Bono National Wildlife Refuge, approximately 0.7 miles east-northeast of the fence line.

It should be noted that all operations impact analyses were based on the emissions shown in **AIR QUALITY Tables 13** through **15**.

Operational Modeling Analysis

The EPA approved ISCST3 model (Version 00101 and 02035) was used to identify the potential ambient air quality impacts from the project's operation. The maximum hourly emissions, as provided in **AIR QUALITY Table 13,** were modeled for each pollutant to determine the short-term impacts (1-hour, 3-hour, 8-hour). The maximum daily and annual emissions, as provided in **AIR QUALITY Table 14 and 15**, were modeled to determine the daily and annual impacts.

AIR QUALITY Table 24 provides the results of the applicant modeling analysis.

AIR QUALITY Table 24
Applicant Operation ISC Modeling Results

Pollutant	Averaging Period	Project Impact (σg/m³)	Background Concentration (σg/m³) [a]	Total Impact (σg/m³)	Limiting Standard (σg/m³)	Type of Standard	Percent of Standard (%)
NO_2 [b]	1-Hour	209	180	389	470	CAAQS	83
	Annual	0.5	19	19.5	100	NAAQS	20
PM_{10}	24-Hour	2.3	115	**117.3**	50	CAAQS	**235**
	Annual Geometric	0.3	38.6	**38.9**	30	CAAQS	**130**
CO	1-Hour	1,121 [c]	8,000	9,121	23,000	CAAQS	40
	8-Hour	458 [c]	4,000	4,458	10,000	CAAQS	45
SO_2	1-Hour	22 [c]	73	95	655	CAAQS	15
	3-Hour	16 [c]	63	79	1,300	NAAQS	6
	24-Hour	7.0 [c]	47	54	105	CAAQS	51
	Annual	0.08	5	5.1	80	NAAQS	6
H_2S	1-Hour	12.0	24.6	36.6	42	CAAQS	87

Source: CEOE 2002a, Tables 5.1-43 (PM_{10}), 5.1-57 (NO_2), 5.1-65 (CO), and 5.1-78 (SO_2). CEOE 2003b. Attachment AQ4 – PSA Revised Modeling Table 5.1-49 (H_2S).
Note(s):
a. Background concentration values for this table and all other modeling result tables have been adjusted to the staff recommended values shown in **AIR QUALITY Table 9**.
b. The applicant lists only one diesel engine in the 1-hour modeling runs because the other two will not be tested while the original one is tested. A screening analysis indicated that the fire pump engine generated the highest NO_2 concentrations. The ambient ratio method (factor 0.75) for rural areas was used for annual NO_2 concentrations.
c. These values were determined through a review of the modeling output files provided by the applicant, which conflict with the CO and SO_2 concentration data given in AFC Tables 5.1-63, 64 for CO and Tables 5.1-74 to –76 for SO_2.

As can be seen from the modeling results provided in **AIR QUALITY Table 24**, with the exception of 24-hour and annual PM_{10} impacts, operations impacts are below the state and national standards. It should be noted that the state 24-hour and annual PM_{10} standards are exceeded in the absence of operations emissions from the SSU6 Project.

The project's PM_{10} 24-hour concentration provided in **AIR QUALITY Table 24** is the maximum concentration found any time during the year and most likely does not correspond to the same day as the maximum PM_{10} background concentration shown in the table. Additionally, the ambient conditions that normally cause high PM_{10}

concentrations (high winds during dry periods or low inversion conditions during cold periods) are not the same as the conditions under which maximum PM_{10} impacts from the project would occur. Although the PM_{10} impacts are quite small, because the Salton Sea Air Basin is classified as non-attainment for PM_{10} and violations of the state and federal ambient air quality standards continue to occur, staff considers the project PM_{10} emissions impacts, without appropriate mitigation, to be significant.

The SSU6 Project operating impacts would not cause a new violation of any NO_2, CO, SO_2, or H_2S ambient air quality standard. The PM_{10} impacts from the operation of the SSU6 Project would cause a further exacerbation of violations of the state and federal PM_{10} standards. Offsets will be provided for the net increase in direct PM_{10} emissions from the project.

Potential Temporary Activities Impacts

The applicant modeled the emissions from temporary activities and processes including: (1) well rework/new well drilling, (2) well flow activities, (3) steam vent tanks, and (4) plant startup. This analysis was completed using the ISCST3 model (Version 02035). The following modeling scenarios and assumptions were assumed to assess the impacts to ambient air quality standards (CEOE 2002a, p. 5.1-30 to 33):

- Well rework/new well drilling activities (emissions of PM_{10}, NO_2, SO_2, CO) were modeled using the same inputs and short term emissions as presented for construction impact modeling. Only one well/rig was evaluated (H=14 feet, T=855°F, D=1.33 feet, V=112 fps).
- Well flow activities (PM_{10} and H_2S) were modeled using the same inputs and short term emissions as presented for construction impact modeling.
- Steam vent tank releases (i.e. turbine bypass conditions) will occur at the VRT exhausts. The exhaust flow rates for the VRT exhausts vary slightly by season.
- The cooling towers (PM_{10} and H_2S) were modeled as twenty point sources - one for each cell. Stack temperatures vary by season and by brine throughput.
- The dilution water heaters (PM_{10}, H_2S) were modeled as two point sources (H=45 feet, T=213.1°F, D=8 feet). Stack flow rates vary slightly by season and by brine throughput.
- In cold plant startup conditions, emissions are expected to occur mainly at the Production Test Unit (PTU) and steam vent tanks. Emissions from the cooling towers and dilution water heaters were also considered.
- The PTU (PM_{10} and H_2S) was modeled as one point source.
- The cooling towers (PM_{10} and H_2S) were modeled as twenty point sources - one for each cell. Stack temperatures vary by season and by brine throughput.
- Steam vent tank releases (i.e. turbine bypass conditions) will occur at the VRT exhausts (80 foot stack height). The exhaust flow rates for the VRT exhausts vary slightly by season.
- The dilution water heaters (PM_{10} and H_2S) were modeled as two point sources. Stack velocities vary by season and by brine throughput.

AIR QUALITY Table 25 provides the results of the applicant's modeling analysis. It should be noted that all operations impact analyses were based on the emissions shown in **AIR QUALITY Tables 16** through **19**.

AIR QUALITY Table 25
Applicant's Temporary Activities ISC Modeling Results

Pollutant	Source	Averaging Period	Project Impact (σg/m^3)	Background Concentration (σg/m^3) [a]	Total Impact (σg/m^3)	Limiting Standard (σg/m^3)	Type of Standard	Percent of Standard (%)
NO_2	Well Rework	1-Hour	236	180	416	89	CAAQS	83
PM_{10}	Well Rework	24-Hour	3.5	115	**118.5**	50	CAAQS	**237**
	Well Flow	24-Hour	36	115	**151**	50	CAAQS	**302**
	Steam Vent Tanks	24-Hour	1.8	115	**116.8**	50	CAAQS	**234**
	Plant Startup	24-Hour	20.7	115	**135.7**	50	CAAQS	**271**
CO	Well Rework	1-Hour	82	8,000	8,082	23,000	CAAQS	35
	Well Rework	8-Hour	31	4,000	4,031	10,000	CAAQS	40
SO_2	Well Rework	1-Hour	18.9	73	91.9	655	CAAQS	14
	Well Rework	3-Hour	12	63	75	1,300	NAAQS	6
	Well Rework	24-Hour	2.4[b]	47	49.4	105	CAAQS	47
H_2S	Well Flow	1-Hour	16.2	24.6	40.8	42	CAAQS	97
	Steam Vent Tanks	1-Hour	16.8	24.6	41.4	42	CAAQS	99
	Plant Startup	1-Hour	17.0	24.6	41.6	42	CAAQS	99

Source: CEOE 2002a, Tables 5.1-59 (NO_2), 5.1-68 (CO), and 5.1-82 (SO_2). CEOE 2003b. Attachment AQ4 – PSA Revised Modeling Tables 5.1-45 (PM_{10}) and 5.1-51 (H_2S).
Note(s):
a. Background concentration values for this table and all other modeling result tables have been adjusted to the staff recommended values shown in **AIR QUALITY Table 9**.
b. This value was determined through a review of the modeling output files provided by the applicant, which conflicts with the value presented in AFC Table 5.1-81 (2.8 ug/m^3).

As can be seen from the modeling results provided in **AIR QUALITY Table 25**, with the exception of 24-hour PM_{10} impacts, impacts from temporary activities are below the state and national standards. It should be noted that the state 24-hour PM_{10} standard is exceeded in the absence of emissions from temporary activities from the SSU6 Project.

Although the SSU6 Project PM_{10} impacts are quite small, because the Salton Sea Air Basin is classified as non-attainment for PM_{10} and violations of the state and federal ambient air quality standards continue to occur, the project PM_{10} emissions impacts are, without appropriate mitigation, significant. The SSU6 Project temporary activity PM_{10} impacts are similar in nature to the construction impacts. The maximum concentrations generally occur close to the project site and within the elevated terrain of the Obsidian Butte area.

The incorporation of the VRTs in the plant design has reduced the modeled temporary activity impacts enough where exceedances of the 1-hour H_2S standard are no longer predicted, and this revised design change has also reduced the worst-case 24-hour PM_{10} impacts that result from the temporary activities.

Fumigation Impacts

There is the potential that higher short-term concentrations may occur during fumigation conditions that are caused by the rapid mixing of the plume to ground level. Fumigation conditions are generally only compared to 1-hour standards. The applicant analyzed the air quality impacts during inversion breakup fumigation conditions from the project site. Inversion breakup fumigation typically occurs at sunrise, when sunlight heats ground-level air, resulting in vertical mixing with the stable, early morning air above it. Pollutant emissions that enter this vertically mixed volume of air can cause high concentrations of pollutant at ground level. This phenomenon usually ceases 30 to 90 minutes after sunrise.

The EPA model SCREEN3 (Version 96043) was used by the applicant to estimate potential impacts due to inversion breakup fumigation conditions. The results of the analysis, estimated for the worst-case operating conditions, are summarized in **AIR QUALITY Table 26**.

AIR QUALITY Table 26
SSU6 Project Maximum Inversion Breakup Fumigation Impacts
Applicant SCREEN3 Modeling, 1- Hour Results

Pollutant	Source	Maximum Impact (σg/m^3)	Background (σg/m^3)	Total Impact (σg/m^3)	Limiting Standard (σg/m^3)	Type of Standard	Percent of Standard (%)
NO_2	Emergency Generator 4160[a]	61.4	180	241.4	470	CAAQS	51
H_2S	Cooling Tower Cell	2.17	24.6	26.77	42	CAAQS	64
	Dilution Water Heater	1.02	24.6	25.62	42	CAAQS	61

Source: CEOE 2002a, Table G-20, Appendix G.2.
Note(s):
a. No fumigation was predicted to occur by SCREEN3 for emergency generator 480 or the fire pump because of their shorter plume heights.

As the above table indicates, the fumigation impacts would not exceed applicable 1-hour California Ambient Air Quality Standards (CAAQS). Fumigation impacts for the cooling tower cells, water heaters, and emergency generator 4160 were predicted to occur at 5224, 3440, and 2708 meters from each respective source (CEOE 2002a, p. 5.1-34). The modeled 1-hour fumigation impacts for each of these individual sources were compared to the maximum impacts determined in the applicant's ISCST3 analyses. Fumigation impacts were less than the ISCST3 maximums. Therefore, fumigation will not significantly affect the overall results of the modeling analyses.

Secondary Pollutant Impacts

The project's emissions of gaseous pollutants, primarily NO_x, SO_2, VOC, and NH_3 can potentially contribute to the formation of secondary pollutants, namely ozone and PM_{10}, particularly ammonium nitrate and sulfate/bisulfate PM_{10}.

The formation of ozone can potentially occur due to the emissions of NO_x and VOC. For the SSU6 Project, the total NO_x annual emissions from plant operations are expected to be below 3.7 tons per year, and VOC emissions below 2.2 tons per year; the annual estimated temporary operations (well redrilling/flow testing and startup emissions) NO_x and VOC emissions are expected to be 6.9 tons per year and less than one ton per year, respectively.

There are air dispersion models that can be used to quantify ozone impacts, but they are used for regional planning efforts where hundreds or even thousands of sources are input into the model over an area of several hundred or thousand square miles to determine ozone impacts. There are no regulatory agency models approved for assessing single source ozone impacts. However, because of the known relationship of NO_x and VOC emissions to ozone formation, it can be said that the emissions of NO_x and VOC from the SSU6 Project do have the potential to contribute in some minor unquantified way to higher ozone levels in the region. However, the controlled NO_x and VOC emission levels proposed by the applicant are not expected to measurably contribute to ozone concentrations or deter the District's ozone attainment progress.

Concerning secondary PM_{10} (primarily ammonium nitrate) formation, the process of gas-to-particulate conversion is complex and depends on many factors, including ambient temperature and relative humidity and the presence of other compounds that participate in or aid the reactions that form secondary particulate. Currently, there is not an agency (USEPA or CARB) recommended model or procedure for estimating secondary particulate formation.

Secondary PM_{10} impacts can occur due to emissions of ammonia and NO_x, causing ammonium nitrate formation. Studies have indicated a conversion of NO_x to nitrate of approximately 10 to 30 percent per hour in a polluted environment (CEOE 2002a, p. 5.1-44). Because the project area is not considered a polluted environment like the South Coast Air Basin (i.e. Los Angeles area) or the San Joaquin Valley Air Basin, the applicant assumed a 10 percent per hour conversion rate. At this rate, a total of 0.20 percent (10 percent times 73/3600 seconds) of the NO_x would be converted to particulate matter at the maximum modeled 24-hour NO_x receptor location (assuming an elapsed time of 73 seconds from the source to the receptor location). The maximum modeled 24-hour NO_x concentration was determined to be 94 $\mu g/m^3$. Therefore, the applicant calculates that the maximum 24-hour PM_{10} impact from ammonium nitrate would be 0.19 σg/m³. This concentration is based on the assumption that the diesel fired emergency generators and all of the operations and maintenance equipment are operating continuously for 24 hours. The applicant believes a more realistic scenario would reduce the emissions 10 to 20 times (0.02 to 0.01 σg/m³ PM_{10} formation). Staff is not sure that this approach determines the maximum potential ammonium nitrate secondary particulate impact for two reasons: 1) the modeled NO_x concentrations at more distant receptors may not decrease at a rate that is greater over time than the increase in the secondary PM_{10} conversion rate; and 2) the applicant has not corrected for the higher molecular weight of ammonium nitrate, which accepting their calculation method, should result in a calculated 24-hour ammonium nitrate concentration of 0.33 µg/m³. Staff also believes that the applicant is neglecting the role of the project's significant ammonia emissions, which are more than 700 times the project's NO_x emissions, in secondary PM_{10} formation and its potential impact when it is dispersed towards the more polluted border region of Imperial County, or when the emissions from the border area or adjacent highly populated air basins are transported to the site area. Also, the applicant's analysis doesn't address the regional nature of secondary particulate formation, which is staff's greater concern. The secondary PM_{10} precursor pollutants from this project (NO_x, SO_x, VOC, H_2S and ammonia) will have hours or days in which to convert to secondary particulate while they are in the Salton Sea Air Basin. Therefore, staff considers the project's contribution to secondary particulate to be potentially significant.

The project's ammonia emissions are estimated to be over 2,700 tons per year. Staff believes that the overall emissions balance from Imperial County sources can be characterized as being ammonia rich[1] due to the significant agricultural and geothermal ammonia emission sources and the comparatively small population and industry base. However, this neglects the transport of pollutants from the surrounding air basins (South Coast Air Basin and San Diego County Air Basin) and Mexico, and that emissions transported into the Air Basin are not likely to be ammonia rich. Review of particulate composition data from Imperial County versus those from the center of the San Joaquin County show that the ammonium to nitrate/sulfate particulate mole ratio[2] in San Joaquin County is almost twice that in Imperial County (CARB 2003), which could suggest that either Imperial County is not ammonia rich like the San Joaquin Valley, or that ammonia does not participate in secondary particulate formation as strongly in Imperial County. Similar comparison between Imperial County and San Francisco and San Diego, areas not considered to be ammonia rich, show very similar ammonium to nitrate/sulfate particulate mole ratios as those from Imperial County, which again suggests that Imperial County may not be ammonia rich. Staff has not found any other data to empirically substantiate that Imperial County can be considered to be ammonia rich. Therefore, to be conservative, staff will assume that the air basin is not ammonia rich, or

[1] Ammonia rich refers to the relative amount of ammonia versus nitrogen oxide and sulfur oxide emissions, and means that there is more ammonia available in the atmosphere than the secondary precursor nitrogen oxides and sulfur oxides (i.e. ammonia is not the limiting reactant). Therefore, increasing ammonia emissions in an ammonia rich area would result in a lower potential to form secondary particulate than would increasing ammonia emissions in an area that is not ammonia rich.

[2] The mole ratio is equivalent to the molecules of ammonium divided by the molecules of sulfate and nitrate that would be needed to form secondary ammonium nitrate and ammonium sulfate particulate.

at least is not ammonia rich when there is substantial pollutant transport from other air basins or Mexico.

Staff's review of available particulate composition (sulfate/nitrate/ammonium fraction) data (CARB 2003) shows that the highest nitrate and ammonium concentrations occur during the winter, typically on days with a number of calm wind hours and low wind speeds. Sulfate concentration peaks, on the other hand, often occur when there are strong winds blowing from the south or southeast in the summer. This is consistent with expected elevated sulfur compound emissions that would be transported from Mexicali into Imperial County. Sulfate concentration peaks can also occur in the winter during calm periods, but they are less frequent and generally of lower concentration than the summer peaks.

Staff's limited review of the available particulate data (12/26/1999 to 10/22/2000) indicates that the combined nitrate, sulfate, and ammonium PM_{10} fraction concentrations are approximately ten percent of the total PM_{10} concentrations in Brawley and eight percent in Calexico, with maximum contributions as high as 37 and 29 percent, respectively. If one were to consider the nitrate, sulfate and ammonium to be primarily composed of very fine particulate (i.e. $PM_{2.5}$), as secondary particulate is known to be primarily composed of very fine particulate/aerosol, they would account for 49 percent of the $PM_{2.5}$ in Brawley and 40 percent of the $PM_{2.5}$ in Calexico on average, with maximum contributions as high as 87 and 70 percent, respectively.

Secondary PM_{10} impacts can also occur due to emissions of SO_2 and VOC. As noted above, the VOC emissions are minor and are not expected to generate a significant impact. The total emissions of SO_2 are expected to be below 1 ton per year and will be substantially less if ultra-low sulfur fuel is used in all diesel-fueled equipment, as recommended by staff. Therefore, the conversion of the project's SO_2 emissions to sulfate particulate matter is anticipated to be an insignificant impact.

H_2S emissions may also contribute to secondary particulate formation through the oxidation of H_2S and further reaction to sulfate salts. However, the applicant will be offsetting the SSU6 normal operating H_2S emissions at a 1.2:1.0 ratio and the temporary H_2S emissions at a 1:1 ratio using local contemporaneous emission reductions from the Leathers Power Plant (CEOE 2003b, Response #3d). Therefore, there will be a net reduction in H_2S emissions, and an assumed net reduction in H_2S based secondary particulate formation.

Staff believes that the emissions of NO_x, SO_x, VOC, and particularly ammonia from the SSU6 Project have the potential to contribute to higher secondary PM_{10} (particularly ammonium salt) levels in the region. However, with appropriate PM_{10} and/or PM_{10} precursor offsets, staff believes that these impacts from NO_x, SO_x, and VOC can be mitigated to insignificant levels. However, the project's ammonia emissions cannot be controlled economically (see applicant's proposed operational mitigation) and have the potential to create secondary particulate in quantities that cannot be offset using available emission reduction credits, since there are no available ammonia emission reduction credits.. Therefore, staff believes that the project's uncontrolled ammonia emissions have the potential to create significant secondary particulate impacts.

Initial Commissioning

Plant commissioning is expected to occur after the completion of construction, and therefore is not expected to be combined with any other construction activity. Commissioning is a temporary activity occurring only one time. The commissioning emissions are comprised of steam venting sources, with no fuel combustion sources being active. Therefore, the applicant modeled 1-hour H_2S impacts and 24-hour PM_{10} impacts only.

Plant commissioning emissions, for the worst case operating modes that were modeled, are emitted from three sources, the production test unit (PTU), the VRTs, and the dilution water heaters. The following modeling scenarios and assumptions were assumed to assess the impacts to ambient air quality standards (CEOE 2002a, p. 5.1-26 to 27, and CEOE 2003b, Revised Tables G-5.2 to 5.6):

Scenarios

1. One well venting at the PTU while eight wells emit at the VRTs – Scenario 1.
2. All nine wells releasing at the VRTs – Scenario 2.
3. Individual steam blows during the steam blow period with the VRTs releasing the remaining steam – Scenario 3a, 3b, and 3c.

The sources modeled include the PTU exhaust (Scenario 2), the four VRT exhausts (all five Scenarios), the dilution water heater exhausts (all five Scenarios), and the high pressure (Scenario 3a), standard pressure (Scenario 3b), and low pressure (Scenario 3c) steam blow exhausts. The emissions and flows through the VRTs and dilution water heater exhausts varied depending on the scenario and the number of wells being vented.

The applicant mitigated the commissioning emissions by changing the plant design to incorporate the VRTs that have higher stacks than the former LP/SP/HP steam vent tanks (80 feet versus 60 feet) and that mix the LP, SP, and HP steams prior to exhaust which lowers the worst case exhaust concentration prior to release. This design mitigation has lowered the worst-case modeled commissioning impacts by approximately a factor of two. **AIR QUALITY Table 27** provides the results of the applicants modeling analysis for maximum PM_{10} and H_2S emissions during commissioning.

AIR QUALITY Table 27
Commissioning Modeling Analysis Results

Pollutant	Averaging Period	Project Impact (μg/m³)	Background (σg/m³)	Total Impact (σg/m³)	Limiting Standard (σg/m³)	Type of Standard	Percent of Standard (%)
PM_{10}	24-Hour	16	115	**131**	50	CAAQS	**262**
H_2S	1-Hour	78.5	24.6	**103.1**	42	CAAQS	**245**

Source: CEOE 2003b. Attachment AQ4 – PSA Revised Modeling Tables 5.1-40 (PM_{10}) and 5.1-47 (H_2S).
Note(s):
a. Scenario #1 generated the highest concentrations of PM_{10}. Scenario #3c generated the highest concentrations of H_2S.

As can be seen from the modeling results provided in **AIR QUALITY Table 27**, the commissioning 24-hour PM_{10} and 1-hour H_2S impacts exceed the ambient air quality standards and are therefore significant. Peak plant commissioning emission impacts, without the addition of background concentrations, exceed the California one-hour H_2S standard by a factor of 1.9 (78.5/42=1.87). Plant commissioning activities are anticipated to last about 14 days. Like the construction and temporary emission source modeling, the maximum commissioning impacts occur either very close to the site or in the elevated terrain of the Obsidian Butte area, just to the west of the project site.

Staff conducted a modeling analysis of all of the commissioning activities that could potentially cause exceedances of the CAAQS to determine the likelihood of whether an exceedance of the CAAQS would actually happen considering the short duration of the commissioning activities versus the five years (1995-1999) of meteorological data used to determine maximum impacts. Staff's modeling analysis indicates that, on average, the commissioning activities, with the addition of the 24.6 $\mu g/m^3$ background concentration, would be expected to cause violations of the CAAQS 1-hour standard for approximately five hours at Obsidian Butte and for one hour at Rock Hill. It was determined that, on average, there was only a one in three chance that the commissioning would cause a single 1-hour exceedance of the CAAQS in the center of the City of Calipatria and a one in four chance of an exceedance at the residence at the Sonny Bono Wildlife Refuge. These frequencies are based on the average of the five years of meteorological data that was used in the modeling analysis. There is the potential for substantially higher CAAQS exceedance frequencies depending on the actual emissions and meteorological conditions that occur during the commissioning. Since there is the likely potential for new exceedances of the 1-hour H_2S CAAQS outside of the property boundary, these impacts are considered to be a potentially significant impact. The District has included permit conditions to help control the potential for extremely high H_2S concentrations during commissioning; however, these conditions will not entirely mitigate the potential for CAAQS violations or health impacts that could occur under worst-case emissions and meteorological conditions.

VISIBILITY IMPACTS[3]

The applicant performed air quality modeling analyses to determine impacts to the nearest Class I area. Joshua Tree National Park is located 56.2 to 126.5 kilometers northwest to north-northeast from the closest portion of the SSU6 Project (well pad OB1/N). The CALPUFF Modeling System, operating in a screening mode, was used to assess the potential impacts of the SSU6 Project on air quality concentrations, visibility, and deposition rates for nitrogen- and sulfur-containing species (CEOE 2002a, p. 5.1-40 to 43).

CALPUFF predicted maximum concentrations to be less than one percent of the PSD Class I increments for all pollutants. Because the maximum impacts modeled by the

[3] The applicant has made changes to the plant design that will lower the temporary Operations impacts and that may slightly change the downwash characteristics of the facility. The applicant did not perform a revised visibility impacts modeling analysis to incorporate the design changes. However, staff does not believe that the design changes could affect the findings made based on the initial visibility impact modeling analysis, as they would not substantially change the modeled values and the impacts were found to be well under established significance thresholds.

applicant were less than the proposed USEPA Class I significant impact levels, no additional multisource modeling analyses were required. For visibility, the CALPOST program (the CALPUFF post processing program) predicted the maximum change in light extinction to be less than the 5 percent screening threshold. Therefore, the proposed project does not pose a threat to regional haze at Joshua Tree National Park. For deposition, the CALPOST program predicted nitrogen and sulfur deposition rates lower than the FLAG threshold of 0.005 kilograms per hectare per year for each compound. Therefore, the applicant does not consider the deposition impacts from the proposed project to be significant.

The project would also emit a large quantity of ammonia that could affect visibility. However, considering that the predominate wind direction is away from the nearest Class I areas and the distance to the nearest Class I area is over 50 kilometers, staff expects no significant visibility impacts to occur to Class I areas as a result of the SSU6 Project.

MITIGATION

Construction Mitigation

As described in the applicable LORS section, District Rule 800 limits fugitive dust during the construction phase of a project. Staff will recommend that construction emission impacts be mitigated to the greatest feasible extent including all feasible measures from the LORS, as well as, other measures considered necessary by staff to fully mitigate the construction emissions.

Applicant's Proposed Mitigation

The applicant has proposed to implement the following construction mitigation measures (CEOE 2002a, p. 5.1-45 to 47):

Fugitive Dust Suppression Program (Construction)

- Watering of unpaved roads and disturbed areas at least twice per day
- Limiting speed of vehicles in construction areas to 10 miles per hour or less.
- Increase watering frequency when wind speeds exceed 15 miles/hour.
- Prior to soil disturbance, install windbreaks at the windward sides on construction areas. The windbreaks shall remain in place until the soil is either stabilized or permanently covered.
- Pre-wet soil to be excavated.
- Fifteen minutes prior to soil handling, spray soil with water.
- Cover all trucks hauling dirt, sand, soil or other loose materials and maintain at least 6 inches freeboard between the top of the load and the top of the trailer.
- Maintain cargo compartments so that no spillage or loss of material can occur.
- Clean cargo compartments for all haul trucks at the delivery site, after removal of materials.

- Prior to entering a public roadway, employ tire cleaning and gravel ramps to limit accumulated mud and dirt deposited on the roads.
- Cleanup of spillage and material tracked out or carried out into a paved road surface within 48 hours.
- Sweep public roadways that are used by construction and worker vehicles at least twice a day using dust-sweeping vehicles.
- Sweep newly paved roads at least twice a week.

Well Drilling Construction Emissions

Contractors will be hired by the applicant to conduct well drilling activities. These contractors will be required to have Statewide Portable Equipment Registrations (SPER) issued by CARB or be permitted by Imperial County APCD for their diesel fueled engines. Typical SPER requirements for these types of engines include:

- Engines shall be equipped with turbocharger and aftercoolers.
- The opacity shall be limited to 20 percent or less.
- PM_{10} emissions shall be limited to less than 0.1 grain per dry standard cubic feet (DSCF) corrected to 12 percent CO.
- Limit engine idling time to no more than five minutes and shut down equipment when not in use.
- Limits on fuel use.

Heavy Duty Diesel Construction Equipment

- Limit engine idling time to no more than five minutes and shut down equipment when not in use.
- Perform regular preventive maintenance to prevent emission increases due to engine problems.
- Use low-sulfur fuel meeting California standards for motor vehicle diesel fuel.

The applicant has also agreed to additional specific construction emission mitigation measures in their Joint Mitigation Proposal with CURE (CEOE and CURE 2003), and those measures have been memorialized in staff's Condition of Certification **AQ-C3**.

Staff Proposed Mitigation

Staff is recommending construction PM_{10} emission mitigation measures that include some of the mitigation measures proposed by the applicant and several additional construction PM_{10} emission mitigation measures and compliance assurance measures in Conditions of Certification **AQ-C1** through **AQ-C4**.

Staff recommends Condition of Certification **AQ-C1** to require the applicant to have an on-site construction mitigation manager, who will be responsible for the implementation and compliance of the construction mitigation program. A construction mitigation plan is required to be submitted for approval under staff's recommended Condition of Certification **AQ-C2**. The documentation of the ongoing implementation and compliance with the construction mitigation program would be provided in the monthly construction compliance report.

Staff recommends PM_{10} mitigation measures be provided in Condition of Certification **AQ-C3**. **AQ-C3** includes the following revisions and additions to the fugitive dust mitigation measures proposed by the applicant.

- All large construction diesel engines which have a rating of 100 hp or more shall meet, at a minimum, the 1996 ARB or EPA certified standards for off-road equipment
- All large construction diesel engines which have a rating of 100 hp or more shall be equipped with catalyzed diesel particulate filters (soot filters), unless certified by engine manufacturers or the on-site AQCMM that the use of such devices is not practical for specific engine types.
- The requirement to use ultra low sulfur diesel (ULSD) fuel.
- Paving of all major access/egress routes to the project site and requiring construction workers and deliveries to take paved routes to and from the project site.
- Suspension of fugitive dust causing activities under windy (i.e. sustained winds >25 mph) conditions;
- Incorporation of ICAPCD fugitive dust regulation requirements.

Staff recommends Condition of Certification **AQ-C4** to limit visible emissions from construction activities at the construction sites, and limit the project related construction visible emissions from occurring within 100 feet of occupied structures.

Staff further recommends that the appropriate responsible agencies impose the following mitigation measures for well drilling and well flow emissions:

- The well flow testing shall be completed as expeditiously as possible.
- Well drilling activities shall use engines that meet or exceed the following EPA offroad engine emission standards:

Date of Well Drilling Operation	EPA Offroad Engine Standard
Prior to 2010	Tier 1
2010 to 2015	Tier 2
2015 to 2020	Tier 3
After 2020	Tier 4

- By no later than 2006, well drilling diesel engines shall be required to use ultra-low sulfur diesel fuel.

Adequacy of Proposed Mitigation

Staff believes that the construction air quality impacts will be less than significant with the implementation of the recommended mitigation measures.

Operations Mitigation

Applicant's proposed mitigation

The applicant has proposed to implement the following operation activity mitigation measures (CEOE 2002a, p. 5.1-45 to 47):

Fugitive Dust Suppression Program (Operations)

- All access and internal power plant roads shall be paved with asphalt.
- Limit vehicle speeds and water unpaved access roads to well pads.
- Direct load haul truck with recently dewatered filter cake.
- Use wind break shield or structure at filter cake discharge point.
- Cover all trucks hauling filter cake or other geothermal materials and maintain at least 6 inches of freeboard between the top of the load and the top of the trailer.
- Maintain cargo compartments so that no spillage or loss of material can occur.
- Clean cargo compartments for all haul trucks at the delivery site, after removal of materials.
- Prior to entering a public roadway, employ tire cleaning and gravel ramps to limit accumulated mud and dirt deposited on the roads.
- Cleanup of spillage and material tracked out or carried out into a paved road surface within 48 hours.
- Designate a person to oversee the implementation of the fugitive dust control program.
- Treat the entrance roadways to the construction site with soil stabilization compounds.
- To prevent run-off, place sandbags adjacent to roadways.
- Limit equipment idle times to no more than five minutes.
- Employ electric motors for operations and maintenance equipment when feasible.
- Apply covers or dust suppressants to soil storage piles and disturbed areas that remain inactive for more than two weeks.
- Replace ground cover in disturbed areas as quickly as possible.

Well Flow Testing Mitigation Measures

The brine from a flow test is routed to a well test unit designed to minimize the release of entrained brine, which contributes to the particulate matter and metals release. Other mitigation measures include:

- Brine flow rates shall be limited to 800,000 lb/hr for both production wells and injection wells (CEOE 2003b, Response #3a).
- Flow tests shall last less than 96 hours.

Cooling Tower Mitigation Measures

- H_2S shall be controlled using a LO-CAT System with a control efficiency of 99.5 percent (CEOE 2002a, Appendix G.3).
- Benzene shall be controlled using carbon absorbers with a control efficiency of 95 percent (CEOE 2002a, Appendix G.3).
- Offgassing of H_2S shall be minimized using oxidizers designed to oxidize at least 90 percent of the H_2S in the condensate (CEOE 2003b, Response #3d).
- The cooling tower shall be designed and built with a drift eliminator, such that the drift rate does not exceed 0.0005 percent (CEOE 2002b, DR#5)
- Hexavalent chromium containing compounds will not be used in the circulating water.

Filter Cake Handling Mitigation Measures

- Direct load filter cake into trucks, trailers or bins as it is generated.
- Tarp trailer and bins immediately after loading.
- Use sulfate scale inhibitors to minimize radioactivity from radium (Ra226 and Ra228) and radon from the silica filter cake.

Emergency Generators/Fire Pump Mitigation Measures

- Internal combustion engines shall be equipped with turbochargers and aftercoolers.
- Emergency generators shall meet BACT for NO_x emissions of 6.9 grams/bhp.
- Fuel sulfur level shall be limited to less than 0.05 percent.

Operating and Maintenance Equipment Mitigation Measures

- Equipment shall meet applicable road or non-road 2001 emissions standards.
- Engines will be maintained according to manufacturer’s recommendations per a regular engine maintenance schedule.

Commissioning and Other Temporary Emissions Mitigation Measures

- Vent relief tank stacks shall replace the originally designed steam vent tanks and they shall be designed with an 80-foot stack height above grade level (CEOE 2003b, Response #3b) to ensure maximum dispersion during transient conditions.

The applicant proposes additional mitigation measures to reduce emissions (CEOE 2002b, DR #7a-e):

∉ Use of gasoline for dump trucks, water trucks and boom trucks.

∉ Any trucks idling more than five minutes will be shut off.

∉ Regularly used on-site and off-site roads and loading pads will be paved and maintained (cleaning, etc.) to minimize fugitive dust emissions.

Emissions Controls

As discussed in the facility description section, the applicant will apply air pollution control equipment to limit the project's emission levels. To reduce H_2S emissions, the applicant proposes to use a LO-CAT System with a control efficiency of 99.5 percent in the cooling towers, and oxidizers designed to oxidize at least 90 percent (CEOE 2003b, Response #3d) of the H_2S in the condensate. In addition to the LO-CAT System for H_2S abatement, the project will include a polishing system using a solid bed H_2S removal scavenger system (CEOE and CURE 2003). To reduce benzene emissions, the applicant proposed to use carbon absorbers with a control efficiency of 95 percent. To reduce PM_{10}, the applicant proposes to use appropriate cooling tower drift control technology to reduce the drift rate to 0.0005 percent.

The ICAPCD has found the following equipment to be BACT for the SSU6 Project (District 2003a, b):

∉ LO-CAT System with H_2S polishing system and Biofilter Oxidizer to control H_2S from the non-condensable gas stream and the condensate stream, respectively.

∉ Carbon adsorption system to control benzene emissions from the non-condensable gas stream.

∉ High efficiency mist eliminators rated at 0.0005% drift control to control the PM_{10} emissions from the cooling tower.

∉ Diesel standby generators and fire pump engine BACT determined to be 6.9 grams/BHP for NO_x control, complete combustion technology for PM_{10} control, and use of CARB diesel fuel for SO_2 emissions control.

While ammonia is not a regulated criteria pollutant under federal, state or local air quality regulations, it is a known PM_{10} precursor. Therefore, staff asked the applicant to provide a discussion of potential control technologies for the over 2,750 tons per year of anticipated ammonia emissions. The applicant responded to this in a revised data response to data request #3 that there are two technically feasible measures. The first would be to replace the project's condensate water, used in the cooling tower, with other water sources that would increase local water use by approximately 8,600 acre feet per year and increase operating costs by approximately $3,000,000 per year. Considering the current water supply and water demand in the project area, this is not a preferred option. However, if and when a tertiary treated waste water source becomes available, this option should be investigated further.

The second method would be to control the ammonia in the condensate before it reaches the cooling tower. This technique includes vacuum degasifier(s), ammonia-hydrochloric acid scrubber(s), weak acid cation exchangers, and would require the disposal of over 3 tons of ammonium chloride for every ton of ammonia controlled. The capital and operating cost of this technology was estimated by the applicant to be $2,000,000 and over $3,000,000 per year, respectively. Considering the cost and that this is an unproven technology not achieved in practice, staff does not consider it to be feasible for this project.

In the Preliminary Staff Assessment, staff identified that other technologies, such as the Z-XM™ ammonia removal process licensed by Water Remediation Technologies, LLC, and reverse osmosis membrane technologies may be technically feasible; and asked the applicant to conduct additional research on potentially feasible ammonia control technologies. The applicant reviewed technically feasible technologies and solicited bids from eight potential technology vendors, three of which provided information (CEOE 2003b, Response #2). The Alken-Murrey Corporation proposed to use microbial blend to control H_2S and ammonia in wastewater. However, this firm only sells the microbial products and could not provide a workable system design; therefore, no further review of this technology was conducted. Carbtrol Corporation's proposal indicated that activated carbon was not a practical solution for this application due to the high levels of H_2S and ammonia (i.e. they did not consider the technology to be technologically feasible for this application). ThermoEnergy Corporation proposed a treatment facility for controlling both H_2S and ammonia; however, this alternative would increase annual operating costs by 39% ($8,900,000 per year), which would be economically unsustainable to the SSU6 Project. The applicant's review of the other technologies identified by staff, such as the Z-XM™ ammonia removal process licensed by Water Remediation Technologies, LLC., and reverse osmosis membrane technologies indicated even higher costs than proposed by ThermoEnergy, in addition to serious feasibility issues. Therefore, it was the applicant's finding that it does not appear that an economically feasible method for reducing ammonia concentrations in the condensate exists (CEOE 2003b, Response #2c). Based on these findings, and staff's separate technology literature search, staff believes there are currently no technologically and economically feasible methods to control the project's ammonia emissions.

The applicant also investigated the feasibility of the use of hydrogen peroxide to control the H_2S emissions during well flow tests and initial commissioning. The applicant found that this technology would not be cost effective (CEOE 2003b, page 3). At the stated $128,000 per ton of H_2S controlled for all well testing operations, staff also considers this technology to be cost prohibitive. Considering that, after the design changes made by the applicant, staff has only found the potential for significant impacts from initial commissioning activities and not from any of the temporary operation activities, a single use of this technology for initial commissioning would surely render it even more cost prohibitive.

Emission Offsets

The applicant is required by the District's New and Modified Stationary Source Review Rule (Rule 207) to provide emission offsets for NO_x, CO, SO_x, PM_{10} and VOC emissions equal to or exceeding 137 lbs/day. Based on the total annual operating emissions estimated by the applicant (**AIR QUALITY Table 16**), none of the pollutants exceed the 137 lbs/day threshold, as shown in **AIR QUALITY Table 28.**

AIR QUALITY Table 28
Total Normal Operating Emissions

Pollutant	Tons/Year	Lbs/Day [a] (annual average)
NO_x	3.7	20.3
CO	10.24	56.1
VOC [b]	2.24	12.3
SO_2	0.43	2.4
PM_{10}	13.71	75.1

Source: CEOE 2002b, Revised Table G-13. CEOE 2003a, Data Request Response #113 (VOCs).
Note(s):
a. Assume 365 days/year
b. Cooling tower non-condensable VOC emissions based on 0.176 lb/hr benzene, 0.00485 lb/hr toluene, 0.000594 lb/hr xylenes (Table G-6), and 0.194 lb/hr VOCs (CEOE 2003a, DR #113).

The annual average daily emissions are much less than the maximum daily emissions reported by the applicant, as shown in **AIR QUALITY Table 14**. The applicant chose to take an annual approach because of the many intermittent operating sources. This approach follows the intent of District Rule 101, *Definitions for Potential Emissions*, where potential emissions are defined as "the sum of the maximum emissions from all emission units at a stationary source, based on the maximum design capacity…expressed in terms of pounds per quarter." Pursuant to Rule 207, emissions for PM_{10} and SO_x are determined by multiplying the permitted emission level, in pounds per day, by the permitted operating days per quarter. It should be noted that even if the startup emissions were included in one quarter, the average daily emissions of all pollutants would still remain below the offset threshold (the highest being PM_{10} quarterly emissions at 124 lbs/day).

Although hydrogen sulfide emissions do not require offsets, the applicant is proposing to ensure that the SSU6 Project does not result in a net increase in emissions of H_2S by reducing H_2S emissions at the existing Leathers Power Plant (CEOE 2003b, Response #3d). The applicant has stated that they will ensure the creation of an emission reduction that will offset the SSU6 operating H_2S emission by a ratio of 1.2:1.0 (25.3 tons of emission reduction credits [ERCs]), and temporary H_2S emissions by a ratio of 1:1 (0.9 tons of ERCs) (CEOE 2003b, Response #3d). Existing emissions at the Leathers Power Plant are available in quantities sufficient to produce sufficient offsets, and the applicant is currently in the process of demonstrating the emission reductions from the Leathers Power Plant. The initial source test results (CEOE 2003c) confirm that the biofilter oxidizer will create more than enough emission reduction credits to cover the applicants offset mitigation proposal.

The applicant also proposes to offset PM_{10} emissions from the SSU6 Project by purchasing or maintaining 19.6 tons of PM_{10} emission reduction credits (CEOE and CURE 2003). There are currently no available banked stationary source PM_{10} emission reduction credits; however, there are almost 300 tons of Agricultural Burn PM_{10} ERCs available in the District's bank inventory (District 2003a). These ERCs are created annually and maintain their value if not used via a declining balance system. These offsets retain their full value for two years then are reduced by 25% annually for three years, having no remaining value after five years. The applicant put out a Request for Proposals (RFP) to obtain the necessary PM_{10} emission offsets and a total of 65 separate credit certificates from 18 separate farmer/farm corporation credit holders with a total value of 202.48 tons of PM_{10} offsets responded. This demonstrates that the applicant should not have any trouble maintaining the annual 19.6 tons of agricultural burn ERCs that are necessary to comply with their offset proposal as long is there is no significant decline in the participation of this offset program. Unlike other offset programs, such as traditional stationary source reduction ERC programs or South Coast Air Quality Management District's Reclaim Trading Credit (RTC) program, the agricultural burn ERCs are not available years in the future; and unlike the annual RTC program they cannot be obtained for future years and they have a declining balance when not applied for more than two years past their date of creation. Therefore, for this specific case staff believes it is not reasonable to require that the exact PM_{10} ERCs be identified at this time. Condition of Certification **AQ-5** requires that the applicant provide the first years PM_{10} ERCs 30 days prior to initial commissioning and then annually as required under District regulation.

The District is also requiring in Condition of Certification **AQ-5** that the project owner surrender additional PM_{10} ERCs to offset initial Well Flow Testing and Initial Commissioning PM_{10} emissions.

Staff Proposed Mitigation

Staff believes that the proposed emission controls minimize the project's potential H_2S and direct PM_{10} emissions to the maximum extent feasible.

The applicant is proposing to offset its normal operating PM_{10} and H_2S emissions using a 1.2:1.0 offset ratio. Staff further notes that the applicant's offset package, considering the offset ratio and considering that the District does not credit the NO_x and SO_2 emissions reduced through the cessation of agricultural burning, meets staff's CEQA requirement for a minimum offset ratio of 1:1 PM_{10} and regulated PM_{10} precursor emissions and ozone precursor emissions. Staff considers the proposed offset levels adequate for the normal operating emissions.

The applicant is also proposing to offset temporary H_2S emissions (0.9 tons/year) using a 1:1 offset ratio (CEOE 2003b, Response #3d), and through their mitigation proposal agreement with CURE, will provide an additional 4.31 tons of PM_{10} offsets that can be considered to offset the entire onsite temporary PM_{10} emission sources and to partially offset the offsite emission sources (i.e. well flow testing) that are outside of CEC's jurisdiction, while the District's conditions and regulation will ensure that all of the these temporary emissions, with the exception of future well flow H_2S emissions (i.e. after initial commissioning) that have not been found to create significant impacts, will be offset at a minimum 1:1 ratio. Additionally, the applicant proposes to move the four vent tanks to the emergency relief tank (ERT) location. The ERTs will be removed from the project equipment and the relocated vent tanks will be called vent relief tanks (VRTs). The steam routed to the VRTs will be combined, versus the earlier proposed set pressure steam flows. The VRT stack heights have been redesigned to the recommended 80-foot height above grade level. Overall, these changes result in significant decreases in maximum impacts (CEOE 2003b, Response #3d), and no additional mitigation of the temporary emission sources is necessary. The PM_{10} and H_2S emissions from these sources are substantial. While the commissioning will occur as a one time event, the other temporary emissions are based on annual expected occurrences.

While staff has found significant impacts from the project's unmitigated operating ammonia emissions and commissioning H_2S emissions, staff has determined that no technically feasible and cost effective mitigation measures currently exist to mitigate these potentially significant impacts. The District's commissioning conditions will provide for public noticing prior to initial commissioning and will require ambient monitoring of H_2S during initial commissioning that will help lower the potential for significant health impacts.

Staff has reviewed the applicant's ammonia control technology assessment information and has performed a separate ammonia control technology investigation to find any feasible ammonia emission control measures. Staff agrees with the applicant that currently, there are no technically feasible and cost effective control measures to reduce the SSU6 project ammonia emissions. However, staff also believes that there is the potential for a cost effective ammonia control technology to be developed sometime in the near future, and that there is the potential that an alternative cooling water source may become available in the future. Therefore, staff has developed Condition of Certification **AQ-C13** to require the applicant to provide biennial reports on ammonia control technology feasibility and alternative water use feasibility. Staff also agrees that there are no cost effective measures to further reduce the initial commissioning H_2S impacts to a level of insignificance.

The limits and requirements of these mitigation measures and other compliance demonstration requirements are provided in Staff's recommended Conditions of Certification **AQ-C5 through AQ-C16.** The proposed conditions from the District's Final Review document are provided as recommended Conditions of Certification **AQ-1** through **AQ-38**.

Staff is also proposing mitigation measures for well drilling and well flow testing operations that are outside of the CEC's licensing jurisdiction. We are proposing mitigation measures that the lead agencies responsible for permitting such activities can and should implement.

Adequacy of Proposed Mitigation

The applicant's proposed mitigation measures, plus staff's additional proposed mitigation measures and the District's anticipated proposed conditions, are considered to be adequate to mitigate the project impacts to less than significant for all activities and pollutants, except the project's initial commissioning phase and the project's unmitigated ammonia emissions during operations. Staff finds that there would be significant unmitigable temporary H_2S impacts from initial commissioning. Staff further finds that the project's ammonia emissions would likely create significant secondary PM_{10} impacts. Staff has not identified any feasible mitigation measures that can reduce these impacts.

Commissioning Emissions

The modeling analysis indicates that the unmitigated commissioning H_2S emissions have the potential to cause exceedances of the one-hour H_2S CAAQS. Staff has determined that initial commissioning period operations have the potential to cause significant unmitigated H_2S impacts. The commissioning period is expected to last two weeks. The maximum modeled H_2S impact concentration for commissioning (0.07 ppm, including background) is orders of magnitude lower than the Occupational Health and Safety Administration (OSHA) worker ceiling limit of 10 ppm, or the National Institute for Occupational Safety and Health (NIOSH) Immediately Dangerous to Life or Health (IDLH) concentration of 300 ppm. However, this level is much higher than the lower odor threshold for H_2S (0.0005 ppm) and the H_2S odors may be noticeable as far as Calipatria during initial commissioning. These odor impacts, depending on wind conditions, have the potential to be of nuisance in areas closer to the project site such as the Sonny Bono Wildlife Refuge. Therefore, the H_2S emissions during initial commissioning have the potential to cause "nuisance, or annoyance to any considerate number of persons or to the public" in violation of California State Health and Safety Code, Section 41700.

Staff has selected the CAAQS as the significance threshold for H_2S impacts. Additional information regarding this significance threshold and other H_2S health impacts are as follows (CARB 2000a; OEHHA 1999):

1. At the CAAQS of 42 ug/m3 (0.03 ppm) 83 percent of the population can detect H_2S and 40 percent of the population would be discomforted.
2. There have been odor complaints and reports of nausea when exposed to CAAQS type levels during exposures from geyser emissions.
3. The World Health Organization (WHO) reports that in order to avoid substantial complaints, H_2S concentration should not be allowed to exceed 0.005 ppm during a 30-minute period (WHO's 30-minute advisory level).
4. Annoyance level for 50% of the population is 0.04 ppm.

Staff believes that the CAAQS is an appropriate significance criteria both for LORS compliance and CEQA health and nuisance impacts. The commissioning impacts analysis has shown that the CAAQS could be exceeded at locations far from the site and a modeling frequency analysis indicated that under average ambient conditions, excedances of the CAAQS would be expected for 5 hours at Obsidian Butte and one hour at Rock Hill. Additionally, it is important to note that shorter term (i.e. less than an hour) acute concentrations could be five to ten times higher than the maximum one-hour averages. Considering all of the above, staff has made the determination that initial commissioning will create temporary significant impacts.

A complete review of H_2S sources was conducted by the Applicant to determine mitigation measures to reduce H_2S emissions from intermittent (temporary) sources. Based on this review, the Applicant proposes to limit the brine flow rate to 0.8 million lbs/hr for both the production wells and injection wells and has optimized the stack parameters for the reduced flow rates (CEOE 2003b, Response #3a). Incorporation of these changes into the design reduced normal well flow testing H_2S impacts to below the CAAQS (See **AIR QUALITY Table 25**). For commissioning, the Applicant proposes to move the four vent tanks to the emergency relief tank (ERT) location. The ERTs will be removed and the relocated vent tanks will be called vent relief tanks (VRTs). Steam routed to the VRTs will be combined, versus the earlier proposed set pressure steam flows. Additionally, the Applicant redesigned the VRT stack heights to 80-feet. These changes significantly decreased the maximum H_2S impacts during commissioning (CEOE 2003b, Response #3b), although, as discussed above, commissioning H_2S emissions still have the potential to cause exceedances of the one-hour H_2S CAAQS. The proposed design changes also result in startup and venting emissions impacts that fall below the H_2S CAAQS (CEOE 2003b, Response #3c). The applicant also investigated the use of hydrogen peroxide to control the hydrogen sulfide emissions but it was found to be cost prohibitive ($128,000/ton of H_2S controlled) for well flow testing operations, and the cost would be much higher if this technology were to be implemented on a single event like initial commissioning. Additionally, the applicant will be required, by District Condition of Certification **AQ-1** provide public notice prior to initial commissioning and will also be required to perform ambient monitoring and meet other requirements during initial commissioning that are designed to reduce the potential for significant impacts. However, all of these measures will not completely mitigate the potential for significant H_2S impacts.

In conclusion, staff finds that the applicant has applied all feasible mitigation to control and mitigate the initial commissioning impacts and that the commissioning Conditions of Certification will further reduce the impact potential; however, the remaining unmitigable impacts are still potentially significant.

Unmitigated Ammonia Emissions

The project's unmitigated ammonia emissions, over 2,700 tons per year, have the potential to cause significant secondary particulate formation. Staff believes that the project's ammonia emissions constitute a significant impact related to secondary PM_{10} formation. Secondary particulates are generally composed of fine particulates (i.e. $PM_{2.5}$ fraction) that are more directly related to particulate health effects. Currently, the air basin is in non-attainment with the PM_{10} NAAQS and CAAQS, and on average, near the project site approximately every third day exceeds the CAAQS 24-hour standard, while near the border in Calexico more than four out of every five days on average exceeds the CAAQS 24-hour standard. Additionally, the annual PM_{10} concentrations in the site area are twice the state annual standard and near the border are more than four times the state annual standard.

The relationship between $PM_{10}/PM_{2.5}$ and negative health effects is well established, so any potential regional increase in $PM_{10}/PM_{2.5}$ from an emission source as large as 2,700 tons per year must be considered potentially significant. **Air Quality Table 29** provides the conversion from ammonia to ammonium nitrate and ammonium sulfate based on percentage conversion of the plant's total estimated normal operating ammonia emissions of 2,754 tons per year. This table shows that even at very low conversion percentiles, and based on available studies from other air basins staff might expect that the annual conversion potential would be less than 30%, a very large amount of secondary particulate will be formed.

AIR QUALITY Table 29
Ammonia to Secondary PM_{10} Conversion

Percent Conversion	Ammonium Nitrate	Ammonium Sulfate
1%	104 tons	107 tons
5%	518 tons	534 tons
10%	1,036 tons	1,068 tons
25%	2,589 tons	2,671 tons
50%	5,179 tons	5,342 tons
75%	7,768 tons	8,013 tons
100%	10,358 tons	10,684 tons

Potential control technologies for reducing ammonia concentrations in the condensate were reviewed by the Applicant (CEOE 2003b, Response #3c) and staff, however no feasible and/or economical options were identified by the Applicant or by staff. Additionally, there are no ammonia emission reduction credits available and no defendable method to determine the actual secondary emission potential and appropriate equivalent PM_{10} or PM_{10} precursor emission reductions to mitigate the SSU6 ammonia emissions. Therefore, staff is recommending that the Commission approve Condition of Certification **AQ-C13** that will require the applicant to research new technologies and potential alternative cooling water sources and report to the commission every two years until a cost effective measure or an alternative emission reduction to offset the SSU6 ammonia emissions is implemented.

CUMULATIVE IMPACTS

The applicant, in consultation with Imperial County APCD, performed a preliminary review of the cumulative impacts associated with the SSU6 Project (CEOE 2002a, p. 5.1-44). The Salton Sea Mineral Recovery Facility, located approximately 0.75 miles southeast of the proposed SSU6 Project, received construction permits and is currently in the startup phase for recovering zinc from brine (District 2003a, page 18). The Mineral Recovery Facility emits sulfuric acid mist (SAM), VOCs, and PM_{10}. The facility controls its PM_{10} point source emissions with baghouses and has an emission limit total of 0.145 lb/hr of PM_{10}. Dispersion modeling conducted as part of the application for the Mineral Recovery Facility shows maximum project impacts of 0.95 $\sigma g/m^3$ (24-hour) and impacts of 0.18 $\sigma g/m^3$ (annual) (SSMR 1997). The applicant performed a modeling review to assess the combined PM_{10} effects. The results of the modeling analysis are summarized in **AIR QUALITY Table 30**. The modeling was performed for each year (1995-1999) of the meteorological data set that was used in the modeling analysis. Therefore, there are five different sets of PM_{10} modeling results shown on Table 29.

AIR QUALITY Table 30
SSU6 Project Cumulative Modeling Analysis Maximum Impacts, σg/m³

Pollutant	Source	1995	1996	1997	1998	1999
PM_{10} 24-hour	SSU6 Project[a]	1.9	2.3	2.1	2.1	2.3
	Mineral Recovery Facility[b]	1.0	1.3	1.3	1.4	1.3
	Combined[a]	1.9	2.3	2.1	2.1	2.3
PM_{10} Annual	SSU6 Project	0.3	0.3	0.3	0.3	0.3
	Mineral Recovery Facility[b]	0.2	0.2	0.2	0.3	0.3
	Combined	0.3	0.3	0.3	0.4	0.4

Source: CEOE 2002a, Tables 5.1-93 and 5.1-94.
Note(s):
a. These values were determined through a review of the modeling output files provided by the applicant, which conflict with the values presented in AFC Table 5.1-93.
b. These values are believed to be slightly higher than the values presented in the original Mineral Recovery Facility permit applicant due to the different meteorological data used in the SSU6 cumulative modeling analysis.

As can be seen from the modeling results provided in **AIR QUALITY Table 30**, the results show that there are no significant additive impacts for the two facilities. The maximum 24-hour cumulative impacts were modeled to occur within 0.4 mile from the center of the SSU6 Project site, and the maximum annual impacts were modeled to occur within a mile of the center of the SSU6 Project site.

The IID Water Conservation Transfer Project is currently in the permitting phase. This project has the potential to have an indirect air quality impact in the area. One potential result of this project is a decrease in the Salton Sea water level and therefore an increase in the exposed shoreline area. This effect would increase the potential for windblown dust (PM_{10} emissions). However, staff does not have any specific emission estimates or locations for the increase of windblown dust, nor any point source emissions or stack parameters to model; therefore this project has not been included in the cumulative impact modeling analysis.

ENVIRONMENTAL JUSTICE

Staff has reviewed Census 2000 information that shows the minority population is greater than fifty percent within a six-mile radius of the proposed Salton Sea Unit #6 power plant (please refer to **Socioeconomics Figure 1** in this Staff Assessment), and Census 2000 information that shows the low-income population is less than fifty percent within the same radius. Based on the air quality analysis, staff identified unmitigated significant direct impacts resulting from the construction or operation of the project, and has proposed additional mitigation methods to reduce some of these impacts to insignificant levels. However, staff has not been able to identify feasible mitigation measures to reduce the unmitigated temporary initial commissioning H_2S impacts, as well as the project's unmitigated ammonia emissions impacts to a level of insignificance.

The project's H_2S emissions, during initial commissioning, would have the potential to cause significant short-term impacts. The applicant has redesigned the steam venting system to lower the H_2S concentrations at release and has incorporated staff's suggested stack height of 80 feet. These design changes have reduced potential impacts from initial commissioning by a factor of two. However, the commissioning emissions, which were found by staff to not have economically feasible controls, still would have the potential to cause exceedances of the 1-hour state ambient air quality standard and will have the potential to cause nuisance odors and minor health impacts (such as nausea). Initial commissioning is a one-time event that is scheduled to last a total of only 14 days. Additionally, the applicant will be required, by Condition of Certification **AQ-1** to provide public notice prior to initial commissioning and will also be required to perform ambient monitoring and meet other requirements during initial commissioning that are designed to reduce the potential for significant impacts. It is staff's conclusion that the initial commissioning activities would cause a disproportional impact on the minority populations surrounding the project site.

The secondary PM_{10} impacts that are likely to result from the project's unmitigated ammonia emissions are considered to be regional in nature, and would not be expected to have a significant disproportionate impact on the local area.

COMPLIANCE WITH LORS

FEDERAL

The project is not subject to New Source Review (NSR), PSD, Title IV, or Title V permits.

STATE

With the anticipated mitigation measures (emissions offsets and controls) discussed herein, staff anticipates substantial compliance with Section 41700 of the California State Health and Safety Code. However, as noted previously, the project's initial commissioning period has been found to have significant unmitigable temporary H_2S impacts and would not demonstrate compliance with Section 41700 of the California H&SC.

LOCAL

The Imperial County Air Pollution Control District completed a Final Review of the SSU6 Project on July 25, 2003 (District 2003b), and found that the proposed project is in compliance with all District rules and regulations.

FACILITY CLOSURE

SSU6 has a design life of 30 years, and may operate much longer than that. However, eventually the SSU6 will close, as a result of the end of its useful life; through some unexpected situation such as a natural disaster or catastrophic facility breakdown; or if the facility became economically noncompetitive, forcing decommissioning. When the facility closes, all sources of air emissions would cease and thus all impacts associated with those emissions would no longer occur.

During the operating life of the facility, temporary facility closure may be required and permanent facility closure would eventually be required. Temporary closure constitutes an unexpected shutdown for a period exceeding the time required for normal maintenance (e.g., for overhaul or replacement of steam turbines). Cause for temporary closure might include damage to the plant from an earthquake, fire, storm, or other event. Permanent closure constitutes a complete cessation in operations with no intent to restart operations, due to plant age, damage to the plant that is beyond repair, economic conditions, or other reasons.

The Permit to Operate, issued by the District, is required for operation of the facility and the applicant must pay permit fees annually while it maintains the Permit to Operate. If the applicant chooses to close the facility and not pay the permit fees, then the Permit to Operate would be cancelled. In that event, the project could not restart and operate unless the applicant pays the fees to renew the Permit to Operate.

When permanent closure occurs and if it were decided to dismantle the project's equipment and structures, there would likely be fugitive dust emissions associated with this dismantling effort. A Facility Closure Plan shall be submitted to the Energy Commission Compliance Project Manager and should include the specific details regarding how the applicant plans to demonstrate compliance with the District Rules (i.e. Rule 800 requirements) regarding fugitive dust emission mitigation.

A detailed description of the closure requirements are provided in the General Conditions Including Compliance Monitoring and Closure Plan section of the Staff Assessment.

RESPONSE TO PUBLIC AND AGENCY COMMENTS

No written comments concerning air quality have been received from either the public or from any public agency.

CONCLUSIONS AND RECOMMENDATIONS

Staff has found substantial compliance with federal, state and local LORS; however, two issues remain that, even after exhaustive research by staff and the applicant and facility redesign efforts by the applicant, have been found by staff to create significant impacts. The first issue is the unmitigable initial commissioning H_2S emissions that have the potential to cause new exceedances of the CAAQS and minor health concerns in the areas of maximum impacts. The second issue is significant secondary $PM_{10}/PM_{2.5}$ formation from the project's unmitigable 2,750 tons per year of ammonia emissions. All other construction and operation emission impacts have been reduced to levels of insignificance with the mitigation measures proposed in the Conditions of Certification.

A recommendation to approve this project with findings of overriding considerations is provided in the Executive Summary. If the Commission approves this project staff recommends the following Conditions of Certification.

CONDITIONS OF CERTIFICATION

STAFF CONDITIONS

AQ-C1 The project owner shall fund all expenses for an on-site air quality construction mitigation manager (AQCMM) who shall be responsible for maintaining compliance with conditions **AQ-C2** through **AQ-C4** for the entire project site and linear facility construction. The on-site AQCMM shall have full access to areas of construction of the project site and linear facilities, and shall have the authority to appeal to the CPM to have the CPM stop any or all construction activities as warranted by applicable construction mitigation conditions. The on-site AQCMM shall have a current certification by the California Air Resources Board for Visible Emission Evaluation prior to the commencement of ground disturbance. The on-site AQCMM shall not be terminated without written consent of CPM.

Verification: At least 60 days prior to the start of ground disturbance, the project owner shall submit to the CPM, for approval, the name, current ARB Visible Emission Evaluation certificate, and contact information for the on-site AQCMM.

AQ-C2 The project owner shall provide a construction mitigation plan (CMP), for approval, which shows the steps that will be taken, and reporting requirements, to ensure compliance with conditions AQ-C3 through **AQ-C4**.

Verification: At least 60 days prior to start any ground disturbance, the project owner shall submit to the CPM, for approval, the construction mitigation plan. The CPM will notify the project owner of any necessary modifications to the plan within 30 days from the date of receipt. Otherwise, the plan shall be deemed approved.

AQ-C3 The on-site AQCMM shall submit to the CPM, in the monthly compliance report (MCR), a construction mitigation report that demonstrates compliance with the following mitigation measures:

a) All unpaved roads and disturbed areas in the project and linear construction sites shall be watered until sufficiently wet. The frequency of watering can be reduced or eliminated during periods of precipitation.

b) The main access and egress routes to and from the SSU6 main construction site for construction employees and delivery trucks shall be paved prior to the initiation of construction. All internal power plant roads shall be paved as early as possible. Construction employees and delivery drivers shall use paved roads to access and leave the main construction site.

c) No vehicle shall exceed 10 miles per hour within the construction site.

d) The construction site entrances shall be posted with visible speed limit signs.

e) All vehicle tires shall be inspected and washed as necessary to be cleaned free of dirt prior to entering paved roadways.

f) Gravel ramps of at least 20 feet in length must be provided at the tire washing/cleaning station.

g) No construction vehicles can enter the construction site unless through the treated entrance roadways. Gravel pads shall be installed at all access points to prevent tracking of mud on to public roadways.

h) Construction areas adjacent to and above grade from any paved roadway shall be provided with sandbags or other measures as specified in the Storm Water Pollution Prevention Plan, to prevent run-off to the roadway.

i) All paved roads within the construction site shall be swept twice daily.

j) At least the first 500 feet of any public roadway exiting from the construction site shall be swept twice daily. The use of dry rotary brushes is expressly prohibited except where preceded or accompanied by sufficient wetting to limit the visible dust emissions. Use of blower devices is expressly forbidden.

k) All soil storage piles and disturbed areas that remain inactive for longer than 10 days shall be covered, or be treated with appropriate dust suppressant compounds.

l) All vehicles that are used to transport solid bulk material and that have potential to cause visible emissions shall be provided with a cover, or the materials shall be sufficiently wetted and loaded onto the trucks in a manner to provide at least one foot of freeboard. Bedliners shall be used in bottom-dumping haul vehicles.

m) All construction areas that may be disturbed shall be equipped with windbreaks at the windward sides prior to any ground disturbance. The windbreaks shall remain in place until the soil is stabilized or permanently covered with vegetation.

n) Any construction activities that can cause fugitive dust in excess of the visible emission limits specified in Condition **AQ-C4** shall cease when the wind exceeds 25 miles per hour.

o) All diesel-fueled engines used in the construction of the facility shall be fueled only with ultra-low sulfur diesel, which contains no more than 15 ppm sulfur.

p) All large construction diesel engines, which have a rating of 100 hp or more, shall meet, at a minimum, the 1996 CARB or EPA certified standards for off-road equipment.

q) All large construction diesel engines and drill rig engines, which have a rating of 100 hp or more, shall be equipped with catalyzed diesel particulate filters (soot filters) that achieve the maximum control efficiency commercially feasible, unless certified by engine manufacturers or the on-site AQCMM that the use of such devices is not practical for specific engine types.

r) All diesel-fueled engines used in the construction of the facility shall have clearly visible tags issued by the on-site AQCMM that shows the engine meets the conditions AQ-C3(p) and AQ-C3(q) above.

s) The construction mitigation measures shall include necessary fugitive dust control methods required to maintain compliance with District Rule 800. Where there are similar measures the more stringent requirement shall apply. Where there is an actual conflict between these measures and a substantive control measure requirement of Rule 800, the Rule 800 requirement shall apply.

t) For backfilling during earthmoving operations, water backfill material or apply dust palliative to maintain material moisture or to form crust when not actively handling; cover or enclose backfill material when not actively handling; if required mix backfill soil with water prior to moving; dedicate water truck or large hose to backfilling equipment and apply water as needed; water to form crust on soil immediately following backfilling; empty loader bucket slowly; minimize drop height from loader bucket.

u) During clearing and grubbing, pre-wet surface soils where equipment will be operated; stabilize surface soil with dust palliative unless immediate construction is to continue; and use water or dust palliative to form crust on soil immediately following clearing/grubbing.

v) While clearing forms, use single stage pours where allowed; use water spray, sweeping and/or industrial shop vacuum to clear forms; and avoid use of high pressure air to blow soil and debris from the form.

w) During cut and fill activities, pre-water with sprinklers or wobblers to allow time for penetration; pre-water with water trucks or water pulls to allow time for penetration.

x) Post a publicly visible sign with the telephone number and person to contact regarding dust complaints. This person shall respond and take corrective action with 24 hours.

y) Building pads should be laid as soon as possible after grading unless seeding or soil binders are used.

z) The project owner shall enforce reduced travel speed requirements by drilling and maintenance personnel on unpaved roadways under the control of CEOE.

Observations of visual dust plumes would indicate that the existing mitigation measures are not resulting in effective mitigation. The AQCMM shall implement the following procedures for additional mitigation measures if the AQCMM determines that the existing mitigation measures are not resulting in effective mitigation:

a) The AQCMM shall direct more aggressive application of the existing mitigation methods within 15 minutes of making such a determination.

b) The AQCMM shall direct implementation of additional methods of dust suppression if step a) specified above, fails to result in adequate mitigation within 30 minutes of the original determination.

c) The AQCMM shall direct a temporary shutdown of the source of the emissions if step b) specified above fails to result in adequate mitigation within one hour of the original determination. The activity shall not restart until one full hour after the shutdown. The owner/operator may appeal to the CPM any directive from the CMM to shutdown a source, provided that the shutdown shall go into effect within one hour of the original determination unless overruled by the CPM before that time.

Verification: In the MCR, the project owner shall provide the CPM a copy of the construction mitigation report and any diesel fuel purchase records, which clearly demonstrates compliance with condition **AQ-C3**.

AQ-C4 No construction activities are allowed to cause visible emissions at or beyond the project site fenced property boundary. No construction activities are allowed to cause visible plumes that exceed 20 percent opacity at any location on the construction site. No construction activities are allowed to cause any visible plume in excess of 200 feet beyond the centerline of the construction of linear facilities, or cause visible plumes to occur within 100 feet upwind of any occupied structures.

Verification: The on-site AQCMM shall conduct a visible emission evaluation at the construction site fence line, or 200 feet from the center of construction activities at the linear facility, or adjacent to occupied structures, each time he/she sees excessive fugitive dust from the construction or linear facility site. The records of the visible emission evaluations shall be maintained at the construction site and shall be provided to the CPM on the monthly construction report.

AQ-C5 The project owner shall submit to the CPM for review and approval any modification proposed by either the project owner or issuing agency to any project air permit.

Verification: The project owner shall submit any proposed air permit modification to the CPM within five working days of its submittal either by 1) the project owner to an agency, or 2) receipt of proposed modifications from an agency. The project owner shall submit all modified air permits to the CPM within 15 days of receipt.

AQ-C6 The project owner shall submit to the CPM and Air Pollution Control Officer (APCO) Quarterly Operations Reports, no later than 30 days following the end of each calendar quarter, that include Operations and emissions information as necessary to demonstrate compliance with all operating Conditions of Certification. The Quarterly Operations Report will specifically note or highlight incidents of noncompliance.

Verification: The project owner shall submit the Quarterly Operations Reports to the CPM and APCO no later than 30 days following the end of each calendar quarter.

AQ-C7 No later than 2006, all diesel-fueled engines used in the operation and maintenance of the facility shall be fueled only with ultra-low sulfur diesel, which contains no more than 15ppm sulfur.

__Verification:__ The project owner shall maintain for inspection fuel purchase, or other, records indicating the fuel sulfur content of the diesel fuel being used at the site.

AQ-C8 In addition to a LO-CAT system abating H_2S in the process, the project owner shall install a polishing system using a solid bed H_2S removal scavenger system.

__Verification:__ Prior to initial commissioning the owner/operator shall provide as design drawings of the polishing system to the District and the CEC CPM.

AQ-C9 As a means to decrease maximum impacts below the California ambient H_2S standard during transient conditions, the project owner shall move the four vent tanks to the emergency relief tank (ERT) location. The ERTs shall be removed from the project equipment and the relocated vent tanks will be called vent relief tanks (VRTs). The steam routed to the VRTs will be a mix of SP, LP and HP steams. The VRT stack heights shall be 80-feet in height above grade level.

__Verification:__ Prior to initiation of construction the owner/operator shall provide design layout drawings of the vent relief tanks and stacks, or other suitable proof of the stack height, to the District and the CEC CPM.

AQ-C10 As a means to decrease maximum impacts below the California ambient H_2S standard during well flow tests, the project owner shall limit the brine flow rate to 0.8 million pounds per hour during normal well flow testing for both the production wells and injection wells. In the event that large amounts of drilling mud are present in the well during test flow, brine flow rate may be temporarily increased up to 1.2 million pounds per hour.

__Verification:__ A summary of brine flow rates during normal well flow testing for both production wells and injection wells shall be included in each Quarterly Operations Report.

AQ-C11 The project owner shall provide through chemical monitoring and mass balance, or other means approved by the CPM, quarterly PM_{10} emission estimates for the SSU6 plant to demonstrate that the annual operational emissions are no more than 13.71 tons/year on a 12-month rolling basis.

__Verification:__ The project owner/operator shall provide the CPM with a proposed PM_{10} emission estimation methodology within 30 days of the start of commercial operations and shall provide the PM_{10} emissions estimates in the Quarterly Operations Report.

AQ-C12 The project owner shall provide through chemical monitoring and mass balance, or other means approved by the CPM, quarterly ammonia emission estimates for the SSU6 plant.

Verification: The project owner/operator shall provide the CPM with a proposed ammonia emission estimation methodology within 30 days of the start of commercial operations and shall provide the SSU6 ammonia emissions estimates in the Quarterly Operations Report.

AQ-C13 The project owner shall biennially provide an Ammonia Control Technology and Alternative Water Source Report to the CEC on advances in ammonia control technologies and availability of new alternative cooling water sources. The project owner shall, within two years of identifying any technology or alternative cooling water source that can be implemented at an annualized cost of less than $500 per ton of ammonia emissions reduced, implement such technology or alternative cooling water source provided such implementation will not cause other significant environmental impacts. Alternatively, the applicant may reduce ammonia emissions from other sources, including but not restricted to their other geothermal power plants, in the amount necessary to offset the SSU6 annual emissions as determined through **AQ-C13**.

Verification: The biennial Ammonia Control Technology and Alternative Water Source Report shall be submitted to the CPM by December 15th of the calendar year that is two years after the completion of the initial commissioning of the plant, and subsequently every two years thereafter by December 15th until such time that ammonia controls have been applied to the SSU6 plant or ammonia mitigation has been applied to other sources as allowed in the condition.

AQ-C14 The emissions of particulate matter less than 10 microns (PM_{10}) from the Cooling Towers shall not exceed 2.91 lbs/hr, and the drift eliminator shall be designed to limit drift to no more than 0.0005% of the circulating water flow.

Verification: The project owner shall provide copies of the cooling tower specifications and a vendor warranty of the drift efficiency to the CPM 60 days prior to cooling tower equipment delivery on-site.

AQ-C15 Compliance with the Cooling Towers PM_{10} emission limit shall be determined by circulating water sample analysis by independent laboratory within 60 days of commercial operation and quarterly thereafter.

Verification: The results and field data collected from cooling tower blowdown water samples analysis shall be submitted to the CPM as part of the Quarterly Operations Reports.

DISTRICT CONDITIONS

COMMISSIONING PERIOD CONDITIONS

The following Conditions AQ-1 through AQ-3 shall apply during commissioning period only.

AQ-1 At least 60 days before commissioning, the project owner shall submit a Commissioning Plan. The Plan shall include the following:

1. A public noticing of the commissioning.
2. An H_2S monitoring and mitigation program during the commissioning period.
3. An updated scheduling time for all start-up events as proposed in AIR QUALITY Table 20 Plant Commissioning Schedule.
4. Reporting of all monitoring and commissioning events

Verification: At least sixty days prior to the commissioning period, the project owner/operator shall submit a Commissioning Plan to the District, CARB, USEPA and the CPM. The plan shall include an H_2S monitoring and mitigation program, a schedule for all start-up events, public noticing and reporting requirements. Prior to commissioning, the project owner shall provide documentation of public noticing to the District, CARB, USEPA and the CPM.

AQ-2 The Commissioning Plan may be revised if found necessary by the CPM or APCD.

Verification: The project owner shall submit the Commissioning Plan and any updates of the Plan to the District, CARB, USEPA and CPM for review and approval prior to the commissioning period.

AQ-3 The Commissioning Plan must be approved by the CEC and APCD before commissioning can commence.

Verification: The project owner shall submit the Commissioning Plan and any updates of the Plan to the District, CARB, USEPA and CPM for review and approval prior to the commissioning period.

SS Unit 6 Operations Specifications and Permit Limitations

Compliance

AQ-4 The facility shall be constructed to operate in compliance with the project description, and operating parameters of the Application For Determination Of Compliance and AFC Application dated July 2002, except as may be modified by more stringent requirements of law or these conditions. Non-compliance with any condition(s) or emission specification of this Permit shall be considered a violation and subject to fines and or imprisonment. This Permit does not authorize the emissions of air contaminants in excess of those allowed by USEPA (Title 40 of the Code of Federal Regulation), the State of California Division 26, Part 4, Chapter 3 of the Health and Safety Code, or the APCD (Rules and Regulations). This permit cannot be considered permission to violate applicable existing laws, regulations, rules or statutes of other governmental agencies.

Verification: The project owner shall demonstrate compliance status in the Quarterly Operations Reports.

Emissions Offsets

AQ-5 The project owner shall provide, **before** the construction, placement or testing of any emission source(s), offsets in tons listed per source or sources listed below in TABLE A: Offsets may be in the form of ERCs (Emission Reduction Credits) owned by certified ERC holders registered with the Imperial County Air Pollution ERC Agricultural or Stationary Bank. ERCs must be transacted and validated through the APCD. New well drilling will not coincide with any other stationary emissions source for the entire project that will trigger offsets for other pollutants (other than NO_x and PM_{10}) greater than 137 lbs/day threshold. The actual calculated emissions per source has been multiplied by the ratio 1.2 to 1 to comply with offsetting ratio requirements of Rule 207 for permanent stationary sources and 1 to 1 for temporary sources.

TABLE A

Source(s)	Offset Amount	Offset Source
SS Unit 6 (21.1 tpy) x 1.2 + temporary emissions (0.9 tpy) x1	26.21 tons H_2S	Leathers LP 38 MWe Geothermal Power Plant (70 tons/yr H_2S uncontrolled) control with Biofilters, sparging or APCD approved system
Well Flow Testing (temporary)	5.00 tons H_2S 29.8 tons PM_{10}	ERC Stationary or Ag Bank
SS Unit 6 PM10 (permanent) (Mitigation agreement July 24, 2003)	19.6 tons PM_{10}	ERC Stationary or Ag Bank
Commissioning (temporary)	8.7 tons H_2S 5.63 tons PM_{10}	ERC Stationary or Ag Bank

Verification: The project owner/operator must submit all H_2S ERC documentation to the District and the CPM prior to the start of construction. At least 30 days prior to project commissioning, the project owner shall identify and surrender the permanent and commissioning operations PM_{10} ERCs to the District in the amount shown above and shall provide the CPM with documentation of the ERC surrender. Until such time as the project owner has committed traditional stationary source ERCs to cover the entire permanent offset burden, the project owner shall annually provide to the CPM and the District the agricultural burn secession ERCs being used to offset the project's PM_{10} emissions prior to each calendar or operational year, as required by the District. The project owner shall identify and surrender the well flow testing PM_{10} ERCs to the District as required in the District permit.

On Or Before A Permit To Operate For Unit 6 Can Be Issued

AQ-6 The project owner shall install and have in operation a biofilter system, sparging system, or other APCD approved system at the Leathers LLC power plant capable of reducing 25.3 tons/yr (5.77 lbs/hr) of H_2S at all times.

Verification: The project owner/operator shall make arrangements for periodic inspections of the Leathers LLC power plant by representatives of the District, CARB, USEPA and CEC.

AQ-7 The total emissions rate of Leathers LLC H_2S shall not exceed 17.03 lbs/hr after the installation of the bio-filtrations system.

Verification: The project owner/operator shall submit records of compliance as part of the Quarterly Operations Reports.

AQ-8 The project owner shall obtain PM_{10} offsets in the total amount of 19.6 tons PM_{10} per operating year. Offsets may be obtained through the APCD's Stationary Source and/or Agricultural Burning Emission Reduction Credits (ERCs) Bank list registered with the APCD. The Project owner shall have ERC Certificates in their possession totaling a minimum of 19.6 tons PM_{10} at all times during the operation of SS Unit 6. The Project owner shall surrender 19.6 tons PM_{10} ERC certificate(s) to the APCD prior to initial startup and annually thereafter.

Verification: At least 30 days prior to project commissioning, the project owner shall identify and surrender PM_{10} ERCs in the amount shown above. Until such time as the project owner has committed traditional stationary source ERCs to cover the entire offset burden, the project owner shall annually provide to the CPM and the District the agricultural burn cessation ERCs being used to offset the project's PM10 emissions prior to each calendar or operational year, as required by the District.

AQ-9 The Leather's LLC Permit to Operate # 1927E H_2S emission rate shall be revised to reflect **AQ-7** above.

Verification: The project owner/operator shall maintain the latest version of the Leathers' LLC Permit to Operate on site for the duration of the SS Unit 6 operating lifetime, or until H_2S offsets from a different source have been obtained, and shall be provided to District or CPM upon request.

Standby Internal Combustions Engines

AQ-10 Temporary or permanent internal combustion engines for this project shall not exceed the engine emissions specifications listed for this project. Upon proper notice and findings by the APCO, the project owner shall replace or modify IC engines or apply the use of secondary emissions control measures as directed by the APCO.

Verification: The project owner/operator shall submit records of compliance as part of the Quarterly Operations Reports.

AQ-11 Stationary Standby IC Engines shall be limited to operate not more than 100 hours per year for maintenance purposes.

Verification: The project owner/operator shall submit records of compliance as part of the Quarterly Operations Reports.

AQ-12 All IC Engines shall be equipped with diesel flow and hour meters.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, USEPA and CEC.

AQ-13 The IC engines shall not discharge into the atmosphere any visible air contaminant other than uncombined water vapor, for a period or periods aggregating more than three minutes in any one hour, which is 20% opacity or greater.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, USEPA and CEC.

AQ-14 The project owner shall maintain logs on the premises showing hours of operation and routine repairs of the engines.

Verification: The project owner shall make the logs available for inspection by representatives of the District, CARB, USEPA and CEC.

AQ-15 The project owner shall submit to the APCD fuel usage and hours of operation records.

Verification: The project owner/operator shall submit fuel usage and hours of operation to the District and CPM no later than 30 days after completion of well drilling.

Geothermal Power Plants Startup

AQ-16 Upon plant startups, the project owner shall

1. Notify APCD of the time duration of the anticipated startup.
2. Vent high pressure steam to condenser as soon as technically feasible during startup.
3. Notify APCD upon completion of startup.

Verification: The project owner/operator shall notify the District and CPM seven (7) days prior to an anticipated startup, including both the estimated time and duration of the startup. The project owner/operator shall notify the District and CPM within three (3) days after completion of a startup. The project owner/operator shall make the site available for inspection by representatives of the District, CARB, USEPA and CEC.

Geothermal Power Plant Emissions Standards

AQ-17 Under normal operations, the Project owner shall not exceed a plant wide total emission rate of the following:

Hydrogen Sulfide (NCG + CT Offgassing + DWH)	6.48 lbs/hr
Hydrogen Sulfide (NCG + CT Offgassing + DWH)	4.81 lbs/hr over a 24 hour average
Hazardous Organics (NCG + CT Offgassing + DWH)	0.180 lbs/hr over a 24 hour average

NCG = exhaust from H_2S abatement system
CT Offgassing = cooling tower offgassing
DWH = Dilution Water Heater Stacks

Verification: The project owner/operator shall submit records of compliance as part of the Quarterly Operations Reports.

Geothermal Steam Venting Emissions Standards

AQ-18 Noncondensible gases from the high pressure steam shall be directed to the hydrogen sulfide abatement and carbon absorption units at all times.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, USEPA and CEC.

AQ-19 Emissions of uncontrolled standard and low pressure noncondensible shall be calculated from most recent source tests.

Verification: Project owner/operator shall submit records of compliance as part of the Quarterly Operations Reports.

Monitoring

AQ-20 The project owner shall install and maintain in good working order an APCD approved continuous H_2S in-stack monitor and flow gas meter at the H_2S control system exhaust. The flow gas meter and in-stack monitor shall meet all specification, calibration, accuracy and quality assurance checks as set forth by the manufacturer. The monitor shall be equipped with a data logger capable of recording the continuous gas flow (SCFM) and H_2S concentrations in PPBv/ PPMv and lbs/hr.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and CEC.

AQ-21 The project owner shall submit to the APCD an approved performance test protocol. Testing shall not be conducted without prior APCD approval.

Verification: Thirty (30) days prior to performance testing the owner/operator shall provide a written test and emissions calculation protocol for District and CPM review and approval. The approved protocol shall be in place when written notice for the initial performance tests is submitted. Written notice of the performance test shall be provided to the District ten (10) days prior to the tests so that an observer may be present. A written report with the results of such performance tests shall be submitted to the District and CPM within forty-five (45) days after testing.

AQ-22 The project owner shall establish and submit an approved monitoring protocol and method(s) for monitoring and calculating cooling tower (offgassing) H_2S offgassing and benzene emissions from carbon absorption unit.

Verification: Thirty (30) days prior to initial commissioning the project owner shall submit a monitoring protocol and method(s) for monitoring and calculating cooling tower H_2S offgassing and benzene emissions from carbon absorption unit for District and CPM review and approval. The approved monitoring protocol shall be in place prior to the end of the initial commissioning period.

AQ-23 Unless waived by the APCO, the project owner shall perform annual source testing at (1) the LOCAT/Solid bed H2S scavenger unit/Carbon adsorption exhaust for H_2S and Benzene emissions+ total speciated organic emissions+ total speciated metals; (2) at the cooling tower cells exhaust for H_2S and ammonia and benzene emissions+ total speciated organic emissions+ total speciated metals, and (3) the Dilution Water Heater (DWH) exhaust emissions for H_2S and benzene emissions+ total speciated organic emissions+ total speciated metals and total PM_{10}.

Verification: The annual source test report shall be submitted to the District and CPM as part of the Quarterly Operations Reports. Each annual source test report shall either include the results of the initial compliance test and supplemental source tests for the current year or document the date and results of the last such tests.

AQ-24 Source tests shall be conducted at no less than 85% power capacity of the plant.

Verification: The project owner/operator shall submit records of compliance as part of the Quarterly Operations Reports.

AQ-25 The project owner shall provide the necessary scaffolding and access for source testing.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, USEPA and CEC.

AQ-26 In-stack monitoring equipment shall be available for inspection by the APCD at all times.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, USEPA and CEC.

AQ-27 The project owner shall measure and submit to the APCD monthly, via an approved format, the H_2S concentrations from the continuous H_2S monitor and benzene concentrations from the carbon absorption Unit(s).

Verification: The data required in this condition shall be submitted to the APCD monthly and shall be provided to the CPM in the Quarterly Operations Reports.

AQ-28 The Project owner shall measure and submit to the APCD monthly H_2S brine concentrations prior to flash.

Verification: The data required in this condition shall be submitted to the APCD monthly and shall be provided to the CPM in the Quarterly Operations Reports.

Ambient H_2S Monitoring

AQ-29 The project owner shall, with the cooperation of APCD and CARB, install and support an approved ambient H_2S monitor and supporting equipment at an Ambient Air Quality Station located near Salton Sea Geothermal area. The monitor shall meet all specification, calibration, accuracy and quality assurance check as set forth by the manufacturer. The monitor shall be equipped with a data logger capable of recording the continuous H_2S concentrations in PPB/PPMV.

Verification: The project owner shall make the monitoring site available for inspection by representatives of the District, CARB, USEPA and CEC, and shall make the monitoring data available to the CPM in hardcopy or electronic format upon request.

AQ-30 The monitor shall be in full operation no later than flow testing of the first production well for the SS Unit 6 project.

Verification: The project owner shall make the monitoring site available for inspection by representatives of the District, CARB, USEPA and CEC. The project owner shall inform the CPM within 15 days after the ambient monitoring site becomes operational.

Reporting Requirements

AQ-31 The project owner shall notify the APCD before plant startups.

Verification: The project owner/operator shall notify the District and the CPM at least seven (7) days prior to an anticipated startup, including both the estimated time and duration of the startup.

AQ-32 The project owner shall notify the APCD at least 48 hours before any official source tests. All official tests shall be witnessed by an APCD official.

Verification: The project owner/operator shall notify the District and the CPM at least 48 hours prior to any official source test. The project owner/operator shall provide to the CPM the name of the APCD official who witnessed the source test in the source test report required under condition **AQ-33**.

AQ-33 The project owner shall submit source test results to the APCD no later than 30 days after the initial performance test. All source tests after the performance test shall be submitted no later than February 28^{th} of the subsequent year for the preceding year results.

Verification: Copies of the required source tests shall be submitted to the CPM and the District simultaneously by the schedule required in this condition.

AQ-34 The project owner shall submit to the APCD monthly, the benzene mole concentrations, mass rate (lbs/hr) and total NCG gas flow rate (SCFM and lbs/hr) from the carbon absorption units no later than 15 days the subsequent month for the preceding month and; the project owner shall submit to the APCD monthly, the continuous H_2S concentration (PPMv) and Mass (lbs/hr) no later than 15 days the subsequent month for the preceding month

Verification: The APCD required monthly concentration and flow data shall be provided to the CPM in the Quarterly Operations Reports.

AQ-35 The project owner shall submit annual fuel consumption and hours of operation of diesel standby equipment no later than February 28th of each year for the subsequent year use.

Verification: The project owner/operator shall submit to the CPM the annual fuel consumption and hours of operation of diesel standby equipment in the Quarterly Operations Report for each fourth quarter.

AQ-36 The project owner shall notify the APCD of all emissions exceedances and breakdowns within 24 hours of the occurrences.

Verification: The project owner/operator shall comply with the notification requirements of the District and submit written copies of these notification reports to the CPM and the APCO as part of the Quarterly Operations Reports.

Control and Monitoring Equipment Maintenance

AQ-37 The H_2S and carbon absorption control, and drift eliminators and or other future control devices and monitoring equipments shall be maintained in good working and operating at its maximum control efficiency level specified in accordance to the operating instructions.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, USEPA and CEC.

AQ-38 The Project owner shall keep a sufficient supply of catalyst, reagents and carbon for immediate system replenishment.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, USEPA and CEC.

STAFF RECOMMENDATIONS FOR OTHER AGENCIES WITH JURISDICTION OVER WELL DRILLING/WELL FLOW ACTIVITIES

The following conditions can and should be implemented by the appropriate responsible agencies approving the geothermal resource wells, pads and associated pipelines:

1. The well flow testing shall be completed as expeditiously as possible.
2. All future well drilling operations (i.e. post initial commissioning) shall be permitted and properly offset as required under District Rule 207[4].
3. All future well drilling operations shall be permitted and properly offset as required under applicable District rules and policies.
4. Well drilling activities shall use engines that meet or exceed the following EPA offroad engine emission standards:

Date of Well Drilling Operation EPA Offroad Engine Standard

[4] The District has informed staff that any future (i.e. post initial commissioning) well flow tests will require air quality permitting and will need to be offset based on the daily emission offset thresholds contained in District Rule 207 with the project's normal operating emissions considered as part of the total. Staff has determined that this offset procedure would require the future well flow testing PM_{10} emissions to be offset at more than a 1:1 offset ratio. Future well flow testing H_2S emissions are not expected to cause significant impacts and do not require mitigation under CEQA.

Prior to 2010	Tier 1
2010 to 2015	Tier 2
2015 to 2020	Tier 3
After 2020	Tier 4

5. Alternatively, prior to 2010, well drilling activities shall be controlled in accordance with the construction mitigation agreement made between CEOE and CURE (CEOE and CURE 2003) as follows:
   - All large drill rig engines, which have a rating of 100 hp or more, shall be equipped with catalyzed diesel particulate filters (soot filters) that achieve the maximum control efficiency commercially feasible, unless certified by engine manufacturers that the use of such devices is not practical for specific engine types.
6. By no later than 2006, well drilling diesel engines shall be required to use ultra-low (15 ppm) sulfur diesel fuel.

REFERENCES

CARB (California Air Resources Board) 1999: Guidance for Power Plant Siting and Best Available Control Technology. Issued September 1999.

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CEOE (CE Obsidian Energy, LLC, Calipatria, California) 2002b: Data Request Response Set 1. Submitted to the California Energy Commission on December 2, 2002.

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CEOE (CE Obsidian Energy, LLC, Calipatria, California) 2003b: PSA Workshop Responses 02-AFC-02. Submitted to the California Energy Commission on July 29, 2003.

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CEOE and CURE (CE Obsidian Energy, LLC, Calipatria, California and California Unions for Reliable Energy) 2003: Joint Statement of CE Obsidian Energy LLC and the California Unions for Reliable Energy. July 2003.

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SSMR (Salton Sea Mineral Recovery) 1997: Salton Sea Mineral Recovery Project Application for Authority to Construct Permit for CalEnergy Minerals, Inc., Calipatria, California, by RTP Environmental Associates, Inc. December 1997.

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PUBLIC HEALTH

Testimony of Ramesh Sundareswaran

Editorial Note: The Public Health analysis was originally published with Part 1 of this FSA on August 5, 2003. Since that time additional information has become available, primarily as a result of the completed AIR QUALITY section in this FSA Part 2. For that reason, amendments to the PUBLIC HEALTH section are highlighted by underlining, and the section is republished here in Part 2 of the FSA.

INTRODUCTION

The purpose of this analysis is to determine if toxic air contaminants from the proposed Salton Sea Unit 6 Power Plant Project (SSU6) will have the potential to cause significant adverse public health impacts or to violate standards for public health protection. If potentially significant health impacts are identified, staff will evaluate mitigation measures to reduce such impacts to insignificant levels.

Although staff addresses potential impacts of regulated or criteria air pollutants in the **Air Quality** section of this Final Staff Assessment (FSA), attachment A at the end of this section provides information focussing on the health effects of such pollutants. Impacts on public and worker health from accidental releases of hazardous materials are examined in the **Hazardous Materials Management** section. Health effects from electromagnetic fields are discussed in the **Transmission Line Safety and Nuisance** section. Pollutants released from the project in wastewater streams are discussed in the **Soil and Water Resources** section. Plant releases in the form of hazardous and nonhazardous wastes are described in the **Waste Management** section.

The following sections describe staff's method of analyzing potential health impacts and the criteria used to determine their significance.

METHOD OF ANALYSIS

Staff's analysis addresses toxic air contaminants to which the public could be exposed during the SSU6 Project's construction and routine operation. Following the release of toxic contaminants into the air or water, people may come into contact with them through inhalation, dermal (skin) contact, or ingestion via contaminated food or water.

Air pollutants or contaminants for which no air quality standards have been set are called noncriteria pollutants. Unlike criteria pollutants such as ozone, carbon monoxide (CO), hydrogen sulfide (H_2S), sulfur dioxide (SO_2), or nitrogen dioxide (NO_2), noncriteria pollutants have no state or national ambient (outdoor) air quality standards that specify levels considered safe for everyone.

Since noncriteria pollutants do not have such standards, a four-step process known as health risk assessment is used to estimate the increased risk of health problems in people who are exposed to different amounts of the pollutants. The risk assessment procedure consists of the following steps:

1. identify the types and amounts of hazardous substances that the SSU6 could emit to the environment;
2. estimate worst-case concentrations of project emissions in the environment using dispersion modeling;
3. estimate amounts of pollutants to which people could be exposed through inhalation, ingestion, and dermal contact; and
4. characterize potential health risks by comparing worst-case exposure to safe standards based on known health effects.

Initially, a screening level risk assessment is performed using simplified assumptions that are intentionally biased toward protection of public health. That is, an analysis is designed that overestimates public health impacts from exposure to project emissions. In reality, it is likely that the actual risks from the power plant will be much lower than the risks, which are estimated by the screening level assessment. This is accomplished by examining conditions that would lead to the highest, or worst-case risks, and then using those in the study. Such conditions include:

- using the highest levels of pollutants that could be emitted from the plant;
- assuming weather conditions that would lead to the maximum ambient concentration of pollutants;
- using the type of air quality computer model which predicts the greatest plausible impacts;
- calculating health risks at the location where the pollutant concentrations are calculated (predicted) to be the highest;
- using health-based standards designed to protect the most sensitive members of the population (i.e., the young, elderly, and those with respiratory illnesses); and
- assuming that an individual's exposure to all pollutants occurs for 70 years.

A screening level risk assessment will, at a minimum, include the potential health effects from inhaling hazardous substances. Some facilities may also emit certain substances which could present a health hazard from noninhalation pathways of exposure (see CAPCOA 1993, Table III-5). When these substances are present in facility emissions, the screening level analysis includes the following additional exposure pathways: soil ingestion, dermal exposure, and mother's milk (CAPCOA 1993, p. III-19).

The risk assessment process addresses three categories of health impacts: acute (short-term) health effects, chronic (long-term) noncancer effects, and cancer risk (also long-term). Acute health effects result from short-term (1-hour) exposure to relatively high concentrations of pollutants. Acute effects are temporary in nature, and include symptoms such as irritation of the eyes, skin, and respiratory tract.

Chronic health effects are those which arise as a result of long-term exposure to lower concentrations of pollutants. The exposure period is considered to be approximately from ten to one hundred percent of a lifetime (from seven to seventy years). Chronic health effects include diseases such as reduced lung function and heart disease.

The analysis for noncancer health effects compares the maximum project contaminant levels to safe levels called “reference exposure levels” or RELs. These are amounts of toxic substances to which even sensitive people can be exposed for a lifetime and suffer no adverse health effects (CAPCOA 1993, p. III-36). These exposure levels are designed to protect the most sensitive individuals in the population, such as infants, the aged, and people suffering from illness or disease that makes them more sensitive to the effects of toxic substance exposure. The RELs are based on the most sensitive adverse health effect reported in the medical and toxicological literature, and include margins of safety. The margin of safety addresses uncertainties associated with inconclusive scientific and technical information available when the standard was developed and is meant to provide a reasonable degree of protection against hazards that research has not yet identified. The margin of safety is designed to prevent pollution levels that have been demonstrated to be harmful, as well as to prevent lower pollutant levels that may pose an unacceptable risk of harm, even if the risk is not precisely identified as to nature or degree. Health protection is achieved if the estimated worst-case exposure is below the relevant reference exposure level. In such a case, an adequate margin of safety exists between the predicted exposure and the estimated threshold dose for toxicity.

Exposure to multiple toxic substances may result in health effects that are equal to, less than, or greater than effects resulting from exposure to the individual chemicals. Only a small fraction of the thousands of potential combinations of chemicals have been tested for the health effects of combined exposures. In conformance with California Air Pollution Control Officers Association (CAPCOA) guidelines, the health risk assessment assumes that the effects of each substance are additive for a given organ system (CAPCOA 1993, p. III-37). In those cases where the actions may be synergistic (where the effects are greater than the sum), this approach may underestimate the health impact.

For carcinogenic substances, the health assessment considers the risk of developing cancer and assumes that continuous exposure to the cancer-causing substance occurs over a 70-year lifetime. The risk that is calculated is not meant to project the actual expected incidence of cancer, but rather a theoretical upper-bound number based on worst-case assumptions. In reality, the risk is generally too small to actually be measured. For example, the one in one million risk level represents a one in one million increase in the normal risk of developing cancer over a lifetime, at whatever location is estimated to have the worst-case risk.

Cancer risk is expressed in chances per million, and is a function of the maximum expected pollutant concentration, the probability that a particular pollutant will cause cancer (called “potency factors”, and established by the California Office of Environmental Health Hazard Assessment), and the length of the exposure period. Cancer risks for each carcinogen are added to yield total cancer risk. The conservative nature of the screening assumptions used means that actual cancer risks are likely to be lower, or even considerably lower than those estimated.

The screening analysis is performed to assess worst-case risks to public health associated with the proposed project. If the screening analysis predicts no significant risks, then no further analysis is required. However, if risks were above the significance level, then further analysis, using more realistic site-specific assumptions, would be performed to obtain a more accurate assessment of potential public health risks.

SIGNIFICANCE CRITERIA

Energy Commission staff determines the health effects of exposure to toxic emissions based on impacts to the maximum exposed individual. This is a hypothetical person who lives in the place where the highest air concentration of chemicals is located. Staff estimates how much exposure this individual has by making “worst-case” assumptions about how this person lives and works. By estimating exposure to this individual, it can be determined if there is any potential for health concerns.

As described earlier, non-criteria pollutants are evaluated for short-term (acute) and long-term (chronic) noncancer health effects, as well as cancer (long-term) health effects. Significance of project health impacts is determined separately for each of the three categories.

Acute and Chronic Noncancer Health Effects

Staff assesses the significance of non-cancer health effects by calculating a “hazard index”. A hazard index is a ratio comparing exposure from facility emissions to the reference (safe) exposure level. A ratio of less than one signifies that the worst-case exposure is below the safe level. The hazard index for every toxic substance, which has the same type of health effect, is added to yield a total hazard index. The total hazard index is calculated separately for acute and chronic effects. A total hazard index of less than one indicates that cumulative worst-case exposures are less than the reference exposure levels (safe levels). Under these conditions, health protection is likely to be achieved, even for sensitive members of the population. In such a case, staff presumes that there would be no significant non-cancer project-related public health impacts.

Cancer Risk

Staff relied upon regulations implementing the provisions of Proposition 65, the Safe Drinking Water and Toxic Enforcement Act of 1986 (Health & Safety Code, § 25249.5 et seq.) for guidance to determine a cancer risk significance level. Title 22, California Code of Regulations, § 12703(b) states that “the risk level which represents no significant risk shall be one which is calculated to result in one excess case of cancer in an exposed population of 100,000, assuming lifetime exposure”. This level of risk is equivalent to a cancer risk of ten in one million, or $10x10^{-6}$. An important distinction is that the Proposition 65 significance level applies separately to each cancer-causing substance, whereas staff determines significance based on the total risk from all cancer-causing chemicals. Thus, the manner in which the significance level is applied by staff is more conservative (health-protective) than that which applies to Proposition 65.

The significant risk level of ten in one million is consistent with the level of significance adopted by the various Air Boards in California pursuant to Health and Safety Code section 44362(b), which requires notification of nearby residents when an air district determines that there is a significant health risk from a facility.

As noted earlier, the initial risk analysis for a project is typically performed at a screening level, which is designed to overstate actual risks, so that health protection can be ensured. When a screening analysis shows cancer risks above the significance level refined assumptions would likely result in a lower, more realistic risk estimate. If facility risk, based on refined assumptions, exceeds the significance level of ten in one million, staff would require appropriate measures to reduce risk to less than significant. If, after all risk reduction measures had been considered, a refined analysis identifies a cancer risk greater than ten in one million, staff would deem such risk to be significant, and would not recommend project approval.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS)

FEDERAL

Clean Air Act section 112 (42 U.S. Code section 7412)

Section 112 requires new sources, which emit more than ten tons per year of any specified hazardous air pollutant (HAP) or more than 25 tons per year of any combination of HAPs to apply Maximum Achievable Control Technology (MACT).

STATE

California Health and Safety Code sections 39650 ET seq.

These sections mandate the California Air Resources Board (CARB) and the Department of Health Services to establish safe exposure limits for toxic air pollutants and identify pertinent best available control technologies. They also require that the new source review rule for each air pollution control district include regulations that require new or modified procedures for controlling the emission of toxic air contaminants.

California Health and Safety Code section 41700

This section states that “no person shall discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which endanger the comfort, repose, health, or safety of any such persons or the public, or which cause, or have a natural tendency to cause injury or damage to business or property “.

LOCAL

Imperial County Air Pollution Control District (ICAPCD) rules 216, 1001,1002,1003 pertain to the regulations concerning implementation of New Source Review, NESHAP, California Airborne Toxic Control and limitations of hexavalent chromium from cooling towers.

SETTING

This section describes the environment in the vicinity of the proposed project site from the public health perspective. Features of the natural environment, such as meteorology and terrain, affect the project's potential for causing impacts on public health. An emissions plume from a facility may affect elevated areas before lower terrain areas, due to a reduced opportunity for atmospheric mixing. Consequently, areas of elevated terrain can often be subjected to increased pollutant impacts. Also, the types of land use near a site influence the surrounding population distribution and density, which, in turn, affects public exposure to project emissions. Additional factors affecting potential public health impacts include existing air quality and environmental site contamination.

SITE AND VICINITY DESCRIPTION

The proposed site is located on approximately 80 acres of a 160-acre parcel in the unincorporated area of Imperial County. The site lies west of State Highway 111 and north of State Highway 86. It will be within the block bounded by McKendry Road on the north, Boyle Road on the east, Severe Road on the west, and Peterson Road to the south. The entire parcel is being used for row crops currently. The site is at an elevation of approximately 220-227 feet below sea level with terrain that rises slightly away from the site.

The project area is designated as Heavy Agriculture, Geothermal Overlay Zone in the Imperial County General Plan. Existing land uses surrounding the site include agriculture, open space, industrial and residential.

The nearest residence is about 4000 feet northeast of the project site. The next closest residence is about 2 miles to the east. As mentioned above, the location of sensitive receptors near the proposed site is an important factor in considering potential public health impacts. No schools, day care facilities, convalescent homes, or hospitals exist within a 3-mile radius of the site. There are, however, five residences within a 3-mile radius of the site.

METEOROLOGY

Meteorological conditions, including wind speed, wind direction, and atmospheric stability, affect the extent to which pollutants are dispersed into ambient air as well as the direction of pollutant transport. This, in turn, affects the level of public exposure to emitted pollutants and associated health risks. When wind speeds are low and the atmosphere is stable, for example, dispersion is reduced and localized exposure may be increased.

Imperial County has a distinct desert climate, which is reflected by low rainfall, hot summers, mild winters, low humidity, and robust temperature inversions. In the summertime, temperatures may reach 106 degrees F. Daytime winter temperatures are milder, around 70 degrees F. Wind direction is predominately from the west to east throughout the year. It does, however, shift with a southeast component during the fall season.

Atmospheric stability is a measure related to turbulence, or the ability of the atmosphere to disperse pollutants due to convective air movement. Mixing heights (the height above ground level through which the air is well mixed and in which pollutants can be dispersed) are lower during mornings due to temperature inversions and increase during the warmer afternoons. Staff's **Air Quality** section presents more detailed meteorological data.

EXISTING AIR QUALITY

The proposed site is within the jurisdiction of the ICAPCD. By examining average toxic concentration levels from representative air monitoring sites in California with cancer risk factors specific to each contaminant, lifetime cancer risk can usually be calculated to provide a background risk level for inhalation of ambient air. However, the ICAPCD does not have a program to measure levels of toxic air contaminants at such monitoring sites. The air monitoring station closest to the SSU6 project is in Niland, approximately 5 miles northeast of the project site, but only measures criteria pollutants. Consequently, background cancer risk levels at the station are currently unavailable. For comparison purposes, it should be noted that the overall lifetime cancer risk for the average individual in the USA is about 1 in 4, or 250,000 in one million.

SITE CONTAMINATION

Site disturbances will occur during facility construction from excavation, grading, and earth moving. Such activities have the potential to adversely affect public health through various mechanisms, such as the creation of airborne dust, material being carried off-site through soil erosion, and uncovering buried hazardous substances.

On behalf of the applicant, CE Obsidian Energy, LLC (CEOE), a Phase I Environmental Site Assessment (ESA) was conducted by URS Corporation in accordance with American Society for Testing and Materials Standard E 1527-00, Standard Practice for Environmental Site Assessments (CEOE 2002a, Appendix O). The purpose of an ESA is to determine the potential for the presence or likely presence of any hazardous substances or petroleum products under conditions that may indicate a release or threat of a release from present or past activities. The results of the ESA are summarized in staff's **Waste Management** section.

IMPACTS

CONSTRUCTION

Emissions Sources

Potential risks to public health during construction may be associated with exposure to toxic substances in contaminated soil disturbed during site preparation, as well as from heavy equipment operation both during site preparation and well drilling, and well flow testing. Criteria pollutant impacts from the operation of heavy equipment and particulate matter from earth moving are examined in staff's **Air Quality** analysis. AFC table 5.1-21 refers to criteria emissions and table 5.1-20 refers to the noncriteria pollutants anticipated during the construction of the SSU6 project. Section 5.1.2.2 of the AFC provides a detailed discussion of the emission sources during construction of the SSU6 project.

As described in the **Waste Management** section, a Phase I Environmental Site Assessment (ESA) has been performed. There is no inherent onsite contamination that warrants further action as discussed in the **Waste Management** section.

The operation of off-road construction equipment will result in air emissions from diesel-fueled engines. Although diesel exhaust contains criteria pollutants such as nitrogen oxides, carbon monoxide, and sulfur oxides, it also includes a complex mixture of thousands of gases and fine particles. These particles are primarily composed of aggregates of spherical carbon particles coated with organic and inorganic substances. Diesel exhaust contains over 40 substances that are listed by the U.S. EPA as hazardous air pollutants and by the California Air Resources Board (CARB) as toxic air contaminants.

Exposure to diesel exhaust causes both short- and long-term adverse health effects. Short-term effects can include increased coughing, labored breathing, chest tightness, wheezing, and eye and nasal irritation. Long-term effects can include increased coughing, chronic bronchitis, reductions in lung function, and inflammation of the lung. Epidemiological studies also strongly suggest a causal relationship between occupational diesel exhaust exposure and lung cancer.

Based on a number of health effects studies, the Scientific Review Panel on Toxic Air Contaminants (SRP) recommended a chronic REL (see REL discussion in Method of Analysis section above) for diesel exhaust particulate matter of 5 $\mu g/m^3$ and a cancer unit risk factor of $3x10^{-4}$ $(\mu g/m^3)^{-1}$ (SRP 1998, p. 6). The SRP did not recommend a value for an acute REL, since available data in support of a value was deemed insufficient. On August 27, 1998, the ARB listed particulate emissions from diesel-fueled engines as a toxic air contaminant and approved SRP's recommendations regarding health effect levels.

Construction of the SSU6 is anticipated to take place over a period of twenty months. As noted earlier, assessment of chronic (long-term) health effects assumes continuous exposure to toxic substances over a significantly longer time period, typically from seven to seventy years. However, the risk of cancer is proportional to the length of exposure and can be calculated by adjusting for the relatively short construction period. This risk is presented below.

AFC Section 5.15.2.1.2 and Appendix G present estimates of diesel exhaust emissions from construction activities. The two contributory sources of diesel are the plant construction equipment and well drilling (CEOE 2002a). Equipment that can be expected to generate diesel emissions includes drill rigs, cranes, trucks, graders, generators, welding equipment, compressors and water pumps. The maximum annual sum of these two categories results in an impact exposure of 0.35 micrograms per cubic meters, north and east of the site. The lifetime cancer risk per individual based on the combination of this exposure and a diesel particulate unit risk factor of $3.0x10^{-4}$ is estimated to be 2.5 in one million (CEOE 2002l). The conservative nature of the screening assumptions used means that the estimated risk is overstated and the actual cancer risks are likely to be lower or even considerably lower than the estimate.

In order to mitigate potential impacts from particulate emissions during the operation of diesel-powered construction equipment, **Air Quality** staff recommends the use of ultra low sulfur diesel fuel and the use of either CARB certified 1996 diesel engines or the installation of soot filters on diesel equipment. The catalyzed diesel particulate filters are passive, self-regenerating filters that reduce particulate matter, carbon monoxide, and hydrocarbon emissions through catalytic oxidation and filtration. The degree of particulate matter reduction is in the range of approximately 85-92 percent. Such filters will reduce diesel emissions during construction and further reduce any potential health impacts. These mitigation measures are required by Condition of Certification **AQ-C3** in the **Air Quality** section of this FSA.

OPERATION

Emissions Sources

Sources of air emissions at the SSU6 plant include cooling towers, steam vent tanks, emergency generators, fire pumps, filter cakes, miscellaneous operation and maintenance equipment and steam blow lines. Most of the emissions are expected from the cooling towers and are to be emitted as offgases, drift and dispersed noncondensible gases. Radon emissions are associated with the temporary storage of the filter cake, that is generated from the extraction of the geothermal fluids, in addition to emissions from the cooling towers during routine operations. AFC section 5.1.2.3 provides a detailed discussion of the various emission sources.

As noted earlier, the first step in a health risk assessment is to identify potentially toxic compounds that may be emitted from the facility.

Table 5.15-8 of the AFC lists non-criteria pollutants that may be emitted from the project along with their anticipated amounts. Pollutants include but are not limited to ammonia, arsenic, benzene, ethylbenzene, hydrogen sulfide, mercury, radon, diesel particulates and xylenes. Table 5.15-3 of the AFC lists toxicity values used to characterize cancer and noncancer health impacts from project pollutants. The toxicity values include reference exposure levels, which are used to calculate short-term and long-term noncancer health effects, and cancer unit risks, which are used to calculate the lifetime risk of developing cancer, as published in the California Air Pollution Control Officers Association (CAPCOA) Guidelines (CAPCOA 1993). **Public Health Table 1** lists toxic emissions and shows how each contributes to the health risk analysis. For example, the first row shows that ammonia is not a carcinogen, but if inhaled, may have chronic (long-term) noncancer health effects and acute (short-term) noncancer effects.

Public Health Table 1
Types of Health Impacts Attributed to Toxic Emissions

Substance	Cancer	Noncancer (Chronic)	Noncancer (Acute)
Ammonia		a	a
Arsenic	a	a	a
Benzene	a	a	a
Beryllium	a	a	
Cadmium	a	a	
Chromium	a	a	
Copper		a	a
Ethylbenzene		a	
Hydrogen sulfide		a	a
Lead	a	a	
Mercury		a	a
Manganese		a	
Nickel	a	a	a
Diesel-PM10	a	a	
Selenium		a	
Radon	a		
Toluene		a	a
Xylene		a	a
Zinc		a	

Source: AFC Table 5.15-2 using reference exposure levels and cancer unit risks from CAPCOA Air Toxics "Hot Spots" Program Revised 1992 Risk Assessment Guidelines, October 1993 and SRP 1998.

Emissions Levels

Once potential emissions are identified, the next step is to quantify them by conducting a "worst case" analysis. Maximum hourly emissions are required to calculate acute (one-hour) noncancer health effects, while estimates of maximum emissions on an annual basis are required to calculate cancer and chronic (long-term) noncancer health effects.

AFC Tables 5.15-8 and 5.15-9 show annual and maximum hourly emissions for the routine operations of the SSU6 project.

The next step in the health risk assessment process is to estimate the ambient concentrations of toxic substances. This is accomplished by using a screening air dispersion model and assuming conditions that result in maximum impacts. The screening analysis was performed using the U.S. EPA approved ISCST3 dispersion modeling program and the ACE 2588 model. The ACE 2588 model uses ISCST3 output in conjunction with source emission rates and toxicity factors, to estimate human health effects. Further, for radon gas the CAP88 Clean Air Act Package model was used to verify the atmospheric dispersion estimated by the ISCST3 model. This method of assessing health effects is consistent with the CAPCOA Air Toxics "Hot Spot" Program Revised 1992 Risk Assessment Guidelines (October 1993) referred to earlier, and results in the following health risk estimates.

Impacts

The screening health risk assessment for the project resulted in a maximum acute hazard index of 0.881 at the eastern boundary of the SSU6 facility (the point of maximum impact, or PMI). The maximum acute hazard index at a sensitive receptor (the maximum exposed individual, or MEI) is 0.310. The chronic hazard index at the PMI is 0.156. The maximum chronic hazard index to occur at the MEI is 0.0604. As **Public Health Table 2** shows, both acute and chronic hazard indices are below the REL of 1.0, indicating that no short- or long-term adverse health effects are expected.

Cancer Risk

As shown in **Public Health Table 2**, the maximum incremental lifetime cancer risk (PMI) was estimated to be 2.88 in one million, approximately 0.3 miles east of the SSU6 project site. The total worst case individual cancer risk (MEI) is calculated to be 1.07 in one million at a location approximately 2 miles east of the project site. For radon, the total worst case individual cancer risk (MEI) is estimated to be 0.135 in a million for the radon emissions from the cooling tower and one in a million for emissions from the filter cake storage. All the risk estimates are well below the significance level of 10 in one million.

Public Health Table 2
Operation Hazard/Risk

Type of Hazard/Risk	Hazard Index/Risk	Significance Level	Significant?
ACUTE NONCANCER	0.881	1.0	No
CHRONIC NONCANCER	0.156	1.0	No
INDIVIDUAL CANCER	2.88×10^{-6}	10.0×10^{-6}	No

Source: CEOE 2002a, Section 5.15.2.1.4

Cooling Tower

In addition to toxic air contaminants, the possibility exists for bacterial growth to occur in the cooling tower, including Legionella. Legionella is a type of bacteria that grows in water (optimal temperature of 37∀C) and causes Legionellosis, otherwise known as Legionnaires' disease. Untreated or inadequately treated cooling systems in the United States have been correlated with outbreaks of Legionellosis. These outbreaks are usually associated with building heating, ventilating, and air conditioning (HVAC) systems but it is possible for growth to occur in industrial cooling towers. In fact, Legionella bacteria have been found in drift droplets. The U.S. Environmental Protection Agency (U.S. EPA) published an extensive review of Legionella in a human health criteria document (EPA 1999). The U.S. EPA noted that Legionella survival is enhanced by symbiotic relationships with other microorganisms, particularly in biofilms and that aerosol-generating systems such as cooling towers can aid in the transmission of Legionella from water to air. Numerous outbreaks of Legionellosis have been linked to cooling towers and evaporative condensers in hospitals, hotels, and public buildings, clearly establishing these water sources as habitats for Legionella. Kool et al (2000) found that Legionella was detected in water systems of 11 of 12 hospitals in San Antonio, Texas. Interestingly, the number of legionnaires' disease cases in each hospital correlated better with the proportion of water-system sites that tested positive for Legionella (p=0.07) than with the concentration of Legionella bacteria in water systems (p=0.23). According to the EPA, in most cases, disease outbreaks resulting from Legionella aerosolizations have involved indoor exposure or outdoor exposure within approximately 650 feet of the source. The U.S. EPA has inadequate quantitative data on the infectivity of Legionella in humans to prepare a dose-response evaluation. Therefore, sufficient information is not available to support a quantitative characterization of the threshold infective dose of Legionella. Thus, the presence of even small numbers of Legionella bacteria presents a risk - however small - of disease in humans.

The U.S. EPA also published a Legionella Drinking Water Health Advisory (EPA 2001) noting that there are several control methods for disinfecting water in cooling systems, including thermal (super heat and flush), hyperchlorination, copper-silver ionization, ultraviolet light sterilization, ozonation, and instantaneous steam heating systems

One technical paper (Addiss, David, et al. 1989) describes cases of Legionnaires' Disease due to cooling tower drift in a town in Wisconsin in the summer of 1986. The authors noted that of five cooling towers in the area, the tower associated with the Legionnaires' disease was the only one that did not use chemical biocides. Furthermore, the cooling tower was "old" (built before 1986) and the water temperature was 41°C, which is in the middle of the "active growth" range of 25-55°C for Legionella. There were no problems caused by the other four cooling towers, which treated their cooling water. Another technical paper (Bhopal, R.S., et al. 1991) addressed the relative risk of contacting Legionnaires' Disease when living in the proximity of cooling towers. The relative risk of 3.0 within approximately 1700 feet of the cooling tower drops to a risk of 1.19 at distances of approximately 1700-2500 feet of the cooling tower. Placed into context of the proposed SSU6 project, the distance to the nearest residential receptor is about 4000 feet. In conclusion, these two articles provide evidence that older cooling towers with untreated water can be a source of Legionella, but that if chemical biocides are used or residences are located further than approximately 2500 feet away, the risks of contracting Legionnaires' disease would be very low.

A paper presented at the 1978 annual meeting of the Cooling Technology Institute (CTI) notes that aerosol particles or droplets larger than 600 micrometers would be expected to fall to the surface within a few hundred meters of the cooling tower (Adams, Paul A. and Lewis, Barbara 1978). Drift eliminators would remove these larger aerosol particles down to a size of about 100 - 200 micrometers. These small particles may be expected to travel long distances downwind in the diffusing cooling tower plume. Bacterial aerosol concentrations in the vicinity of and downwind of cooling towers are affected by: quality of makeup water, type of biofouling control, effect of biological oxygen demand (BOD) in makeup water, wind speed, height of tower, speed and efficiency of the vent fans, stability of the atmosphere and temperature differential between exit and ambient air. The potential public health hazard from microbial aerosols within a cooling tower plume is difficult to estimate.

Another paper presented at the 1982 CTI annual meeting (Tyndall R.L. 1982) discussed the profiles and infectivity of Legionella bacteria populations in cooling towers. A survey of both industrial and air conditioning cooling towers was conducted for the presence of this bacterium which showed that while the majority of cooling water tested contained more than 10,000 bacteria per liter of water, chlorine can be effective in controlling Legionella concentrations in some cooling towers. The authors concluded that generalizations concerning the content and serotypic profiles of Legionella in cooling towers at any given site cannot be made and that each cooling tower needs to be individually assessed. It also appears that some biocides routinely used to control bacteria in cooling tower waters are not always effective against Legionella.

In 2000, the CTI issued its own report and guidelines for the best practices for control of Legionella (CTI 2000). The CTI found that 40-60 percent of industrial cooling towers tested were found to contain Legionella. It estimated that more than 4,000 deaths per year are believed to occur from Legionellosis (from all sources, not limited to industrial cooling towers), but only about 1,000 are reported. The CTI listed no reference or supportive data for this assertion, however. It also noted that continuous chlorine- or bromine-based biocide free residuals of 0.5 to 1.0 ppm in the cooling tower hot return water have been recommended by many agencies and that biodispersants and biodetergents may aid in the penetration, removal, and dispersion of the biofilm which often builds up on the inside of pipes. Furthermore, the use of these dispersants and detergents often increases the efficacy of the biocide.

To minimize the risk from Legionella, the CTI noted that consensus recommendations included minimization of water stagnation, minimization of process leads into the cooling system that provide nutrients for bacteria, maintenance of overall system cleanliness, the application of scale and corrosion inhibitors as appropriate, the use high-efficiency mist eliminators on cooling towers, and the overall general control of microbiological populations.

Nalepa, et al (2002) researched the effectiveness of bromine-based biocides on microbial biofilms and biofilm-associated Legionella Pneumophila. Biofilms in cooling systems contribute to a reduction in heat transfer, increase in energy consumption, increase in corrosion, and an increase in health risk. The authors noted that world-wide, deadly outbreaks of Legionnaires' disease continue to take place with regularity despite a growing list of published guidelines and recommended practices by CTI and other industry groups and governmental agencies. The results of studies indicate that the bromine-based biocides may be more effective than chlorine-based biocides against aged, more difficult to kill biofilms. However, the authors concluded that when properly applied, oxidizing biocides could be part of an overall water treatment program that incorporates effective microbiological control, scale, and corrosion inhibition strategies together with regular maintenance practices.

Good preventive maintenance is important in the efficient operation of cooling towers and other evaporative equipment (ASHRAE 1998). Preventive maintenance includes having effective drift eliminators, periodically cleaning the system if appropriate; maintaining mechanical components in working order, and maintaining an effective water treatment program with appropriate biocide concentrations. Staff notes that most water treatment programs are designed to minimize scale, corrosion, and biofouling and not to control Legionella.

In summary, the scientific and technical trade literature are replete with examples of Legionella bacterium present in industrial cooling towers, other building HVAC systems, and indeed, surface waters throughout the world. Health experts have not found a concentration of this bacterium which would not present some risk of infection to the public, that is, a concentration in water below which would be deemed totally “safe”. Evidence supports the fact that despite water temperature and biocide control, a thin “bio-film” can form on the inside walls of piping and serve to protect the bacteria from the biocide and temperature variations. Additional chemical additives, mechanical removal, and/or “back-flushing” of the system can be used to remove this bio-film.

The following management strategies are directed at minimizing colonization, amplification within the equipment, or both (ASHRAE 1998 and 2000):

∉ Avoid piping that is capped and has no flow (dead legs).

∉ Control input water temperature to avoid temperature ranges where Legionella grow. Keep cold water below 25∀C (77∀F) and hot water above 55∀C (131∀F).

∉ Apply biocides in accordance with label dosages to control growth of other bacteria, algae, and protozoa that may contribute to nutritional needs of Legionella. Rotating biocides and using different control methods is recommended. These include thermal shock, oxidizing biocides, chlorine-based oxidants and ozone treatment.

∉ Conduct routine periodic “back-flushes” to remove bio-film buildup on the inside walls of the pipes.

In order to ensure that Legionella growth is kept to a minimum, staff has proposed Condition of Certification **Public Health-1**. The condition would require the project owner to prepare and implement a biocide and anti-biofilm agent monitoring program to ensure that proper levels of biocide and other agents are maintained within the cooling tower water at all times, that periodic measurements of Legionella levels are conducted, and that periodic cleaning is conducted to remove bio-film buildup. Staff believes that with the use of an aggressive antibacterial program coupled with routine monitoring and biofilm removal, the chances of Legionella growing and dispersing would be reduced to insignificance.

CUMULATIVE IMPACTS

The maximum impact location occurs where pollutant concentrations from the SSU6 project would theoretically be the highest. Even at this location, staff does not expect any significant change in lifetime risk to any person, and the increase of 2.88 in one million does not represent any real contribution to the average lifetime cancer risk of 250,000 in one million. Modeled facility-related residential risks are lower at more distant locations, and actual risks are expected to be much lower, since worst-case estimates are based on conservative assumptions, and overstate the true magnitude of the risk expected. Therefore, staff does not consider the incremental impact of the additional risk posed by the SSU6 Project to be either significant or cumulatively considerable.

The worst-case long-term noncancer health impact from the project (0.156 hazard index) is well below the significance level of 1.0 at the location of maximum impact. Similarly, the worst-case acute health impact of 0.881 is below the significance level of 1.0. At these levels, staff does not expect any cumulative health impacts to be significant. As with cancer risk, acute and long-term hazards would be lower at all other locations and cumulative impacts at other locations would also be less than significant.

Even in the unlikely event that worst-case emissions from an existing facility were to coincide both geographically and temporally with SSU6 emissions at the location of maximum impact, the overall health outlook would not change for anyone. Thus, the SSU6 project will not result in any significant cumulative cancer or noncancer health impacts during normal facility operations. As noted in the Air Quality section, however, H_2S emissions during commissioning activities have the potential to combine with ambient levels of H_2S to cause new violations of the one-hour California Ambient Air Quality Standard in certain locations, namely Obsidian Butte and Rock Hill. Attachment A to this section describes potential health effects of H_2S and notes that the California standard is welfare based and intended to protect the public against nuisance odors. However, the 30 ppb threshold could be detectable by about 83 percent of the population and be discomforting to approximately 40 percent. These estimates have been supported by odor complaints and reports of nausea and headache at the 30 ppb exposure level from geyser emissions. Because of the potential short-term health effects that could occur at H_2S levels possible during commissioning activities, potential health-related impacts are considered significant by staff.

ENVIRONMENTAL JUSTICE

Staff has reviewed Census 2000 information that shows the minority population is greater than 50 percent within a six-mile radius of the proposed SSU6 project (please refer to **Socioeconomics Figure 1** in this Staff Assessment). Staff also reviewed Census 2000 information that shows the low-income population is less than fifty percent within the same radius.

As discussed in the Air Quality section, there is a likelihood of exceedances of the CAAQS for H_2S at Obsidian Butte and Rock Hill. Neither location, however, comprises residential or work areas for the area's minority population. The modeling frequency analysis conducted for the CAAQS exceedances indicated that such exceedances are unlikely in residential or work areas inhabited by minorities, so that there are not likely to be any significant impacts in those areas. Further, Condition of Certification **AQ-1** mandates that the applicant undertake a variety of measures, including appropriate public notification, of potential CAAQS exceedances at Obsidian Butte and Rock Hill, thereby providing the information necessary for members of the public to avoid any potential H_2S significant impacts associated with the initial commissioning.

COMPLIANCE WITH LORS

Staff concludes that construction and operation of the SSU6 Project will be in compliance with all applicable LORS regarding long-term and short-term project impacts.

FACILITY CLOSURE

The scope of staff's public health analysis is limited to routine releases of harmful substances to the environment. During either temporary or permanent facility closure, the major concern would be from accidental or non-routine releases from either hazardous materials or wastes, which may be onsite. These are discussed in the Hazardous Materials and Waste Management sections, respectively. During temporary closure (periods greater than those required for normal maintenance), it is unlikely that there would be any routine releases of harmful substances to the environment, since the facility would not be operating. For permanent closure, the only routine emissions would be related to facility demolition or dismantling, such as exhaust from heavy equipment or fugitive dust emissions. These would be subject to closure conditions adopted by the Energy Commission once a closure plan is received from the project owner. Please refer to the General Conditions section for more details.

CONCLUSIONS

Staff has analyzed potential public health risks associated with construction and operation of the SSU6 project, and does not expect any significant adverse cancer, or short- or long-term noncancer health effects from project emissions related to normal operation. As noted above, staff considers potential health impacts related to H_2S emissions from commissioning activities to be significant and recommends the Commission approve a finding of overriding considerations for this temporary impact. Implementation of staff's proposed Condition of Certification would also ensure that the risk of Legionella growth and dispersion is reduced to less than significant.

PROPOSED CONDITIONS OF CERTIFICATION

Public Health-1 The project owner shall develop and implement a cooling towers Biocide Use, Biofilm Prevention, and Legionella Control Program to ensure that the potential for bacterial growth is controlled. The Program shall be consistent with staff's "Biocide Monitoring Program Guidelines" or the Cooling Tower Institute's "Best Practices for Control of Legionella" guidelines.

Verification: At least 30 days prior to the commencement of cooling tower operations, the project owner shall submit the Biocide Use, Biofilm Prevention, and Legionella Control Program to the CPM for review and approval.

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ATTACHMENT A
CRITERIA POLLUTANT HEALTH EFFECTS

OZONE (O_3)

Ozone is formed when reactive organic gases are mixed with nitrogen oxides in the presence of sunlight. Heat speeds up the reaction, typically leading to higher concentrations in the summer months. Ozone is a colorless, very reactive gas, which oxidizes other materials. Oxidation damages living cells and tissues by altering their protein, lipid, and carbohydrate components or products. Such damage leads to dysfunction and death of cells in the lung and in other internal tissues.

The U.S. EPA revised the federal ozone standard on July 18, 1997 (62 Fed. Reg. 38856) based on new health studies which became available since the standard was last revised in 1979. These new studies showed that adverse health effects occur at lower ambient concentrations over longer exposure times than those reflected in the previous standard, which was based on acute health effects associated with heavy exercise and short-term exposures. The U.S. EPA's proposed ozone rule lists health effects which have been attributed to result from short-term (one to three hours) and prolonged (six to eight hours) exposure to ozone (61 Fed. Reg. 65719). However, a 1999 federal court ruling blocked implementation of the ozone 8-hour standard. EPA has asked the U.S. Supreme Court to reconsider that decision.

Acute health effects induced by short-term exposures include transient reductions in pulmonary function, and transient respiratory symptoms including cough, throat irritation, chest pain, nausea, and shortness of breath with associated effects on exercise performance. Other health effects associated with short-term or prolonged O_3 exposures include increased airway responsiveness (a predisposition to bronchoconstriction caused by external stimuli such as pollen and dust), susceptibility to respiratory infection by impairing lung defense mechanisms, increased hospital admissions and emergency room visits, and transient pulmonary inflammation.

Generally, groups considered especially sensitive to the effects of air pollution include persons with existing respiratory diseases, children, pregnant women, and the elderly. However, controlled exposure data on people in clinical settings have indicated that the population at greatest risk of acute effects from ozone exposures are children and adults engaged in physical exercise. Children are most at risk because they are active outside, playing and exercising, during the summer when ozone levels are at their highest. Adults who are outdoors and engaging in activities involving heavy levels of exertion during the summer months are also among those most at risk. Exertion increases the amount of O_3 entering the airways and can cause O_3 to penetrate to peripheral regions of the lung where lung tissue is more likely to be damaged. These individuals, as well as those with respiratory illnesses, such as asthma, can experience a reduction in lung function and increased respiratory symptoms, such as chest pain and cough, when exposed to relatively low ozone levels during periods of moderate exertion.

CARBON MONOXIDE (CO)

Carbon monoxide is a colorless, odorless gas, which is a product of inefficient combustion. It does not persist in the atmosphere, but is quickly converted to carbon dioxide. However, it can reach high levels in localized areas, or "hot spots".

CO reduces the oxygen carrying capacity of the blood, thereby disrupting the delivery of oxygen to the body's organs and tissues. Persons sensitive to the effects of carbon monoxide include those whose oxygen supply or delivery is already compromised. Thus, groups potentially at risk to carbon monoxide exposure include persons with coronary artery disease, congestive heart failure, obstructive lung disease, vascular disease, anemia, the elderly, newborn infants, and fetuses (CARB 1989, p. 9). In particular, people with coronary artery disease were found to be especially at risk from carbon monoxide exposure (CARB 1989, p. 9). Tests conducted on patients with confirmed coronary artery disease indicated that exposure to low levels of carbon monoxide during exercise produced significant cardiac effects. These included earlier onset of chest pain (angina) and electrocardiographic changes indicative of effects on the heart muscle (CARB 1989, p. 6). Such changes can limit the ability of patients with coronary artery disease to exert themselves even moderately. Therefore, the statewide carbon monoxide one-hour and eight-hour standards were adopted in part to prevent aggravation of chest pain. Additionally, however, the standards are intended to prevent decreased exercise tolerance in persons with peripheral vascular disease and lung disease, impairment of central nervous system functions, and increased risk to fetuses (Title 17, Cal. Code Regs., §70200).

PARTICULATE MATTER (PM)

Particulate matter is a generic term for particles of various substances, which occur as either liquid droplets or small solids of a wide range of sizes. Particles with the most potential to adversely affect human health are those less than 10 micrometers (millionths of a meter) in diameter (known as PM10), which may be inhaled and deposited within the deep portions of the lung (PM10). PM may originate from anthropogenic or natural sources such as stationary or mobile combustion sources or windblown dust. Particles may be emitted directly to the atmosphere or result from the physical and chemical transformation of gaseous emissions such as sulfur oxides, nitrogen oxides, and volatile organic compounds. PM10 may be made up of elements such as carbon, lead, and nickel; compounds such as nitrates, organics, and sulfates; and complex mixtures such as diesel exhaust and soil fragments. The size, chemical composition, and concentration of ambient PM10 can vary considerably from area to area and from season to season within the same area.

PM10 can be grouped into two general sizes of particles, fine and coarse, which differ in formation mechanisms, chemical composition, sources, and potential health effects. Fine-mode particles are those with a diameter of 2.5 micrometers or less (PM2.5), while the coarse-mode fraction of PM consists of particles ranging from 10 micrometers down to 2.5 micrometers in diameter.

Coarse-mode PM10 is formed by crushing, grinding, and abrasion of surfaces, and in the course of reducing large pieces of materials to smaller pieces. Coarse particles consist mainly of soil dust containing oxides of silicon, aluminum, calcium, and iron; as well as fly ash, particles from tires, pollen, spores, and plant and insect fragments. Coarse particles normally have shorter lifetimes (minutes to hours) and only travel over short distances (of less than tens of kilometers). They tend to be unevenly distributed across urban areas and have more localized effects than the finer particles.

PM2.5 is derived both from combustion by-products, which have volatilized and condensed to form primary PM2.5, and from precursor gases reacting in the atmosphere to form secondary PM2.5. Components include nitrates, organic compounds, sulfates, ammonium compounds, and trace elements (including metals) as well as elemental carbon such as soot. Major sources of PM2.5 are fossil fuel combustion by electric utilities, industry and motor vehicles, vegetation burning, and the smelting or other processing of metals. Dry deposition of fine mode particles is slow allowing such particles to often exist for long periods of time (of from days to weeks) in the atmosphere and travel hundreds to thousands of kilometers. They tend to be uniformly distributed over urban areas and larger regions and are removed from the atmosphere primarily by forming cloud droplets and falling out within raindrops.

The health effects of PM10 from any given source usually depend on the toxicity of its constituent pollutants. The size of the inhaled material usually determines where it is deposited in the respiratory system. Coarse particles are deposited most readily in the nose and throat area while the finer particles are more likely to be deposited within the bronchial tubes and air sacs, with the greatest percentage deposited in the air sacs. Until recently, PM10 particles had been considered to be the major fraction of airborne particulates responsible for various adverse health effects. The PM10 fraction is known to be capable of penetrating the thoracic and alveolar regions of the human and animal lungs. The PM2.5 fraction, however, was found to pose a significantly higher risk for health. This is due to their size and associated deposition and retention characteristics in the respiratory tract, enabling it to penetrate and deposit within the deeper alveolar regions of the lung. The following aspects of PM2.5 deposition all contribute to the more serious health effects attributed to smaller particles:

- The deposition of PM2.5 favors the periphery of the lungs, which is especially vulnerable to injury for anatomical reasons.
- Clearance of the PM2.5 from within the deeper reaches of the lungs is a much slower process than from the upper regions. Consequently, the residence time is longer, implying longer exposure, and hence greater risk.
- The human anatomy further allows the penetration of the superficial tissues by PM2.5 and entry into the bodily circulation without much effort in the periphery of the lungs.

Many epidemiological studies have shown exposure to particulate matter capable of inducing a variety of health effects, including premature death, aggravation of respiratory and cardiovascular disease, changes in lung function and increases in existing respiratory symptoms, effects on lung tissue structure, and impacts on the body's respiratory defense mechanisms. The underlying biological mechanisms are still poorly understood. Based on their review of a number of these epidemiological studies (as published after 1987 when the federal standards were revised), together with suggestion of PM2.5 concentrations as a more reliable surrogate for the health impacts of the finer fraction of PM than PM10, the U.S. EPA concluded that the then-current standards were not sufficiently stringent to protect against significant effects in exposed humans. Therefore, federal PM standards were revised on July 18, 1997 (62 Fed. Reg. 38652) to add new annual and 24-hour PM2.5 standards to the existing annual and 24-hour PM10 standards. Taken together, these new standards were meant to provide additional protection against a wide range of PM-related health effects, including premature death, increased hospital admissions and emergency room visits, primarily among sensitive individuals such as the elderly, children and individuals with cardiopulmonary diseases such as asthma. Other impacts include decreased lung function (particularly in children and asthmatics), and alterations in lung tissue and structure.

California has also had 24-hour and annual standards for PM10 (CARB 1982, pp. 81, 84). These studies were aimed at establishing the PM10 levels capable of inducing asthma, premature death, and bronchitis-related symptoms. They were set to protect against such impacts in the general population as well as sensitive individuals such as patients with respiratory disease, declines in pulmonary function, especially as related to children (Tit. 17, Cal. Code Regs., §70200). These standards were set to be more stringent than the federal standard, which the ARB regarded as inadequate for the protection desired (CARB 1991, p. 26).

On June 20, 2002, the ARB approved the adoption of a lower annual state standard for PM10, as well as a new annual standard for PM2.5 (CARB 2002). The 24-hour PM10 standard was not changed. The standards were established to prevent excess death, illnesses such as respiratory symptoms, bronchitis, asthma exacerbation, and cardiac disease, and restrictions in activity from short- and long-term exposures (Title 17, Cal. Code Regs., §70200).

NITROGEN DIOXIDE (NO_2)

Nitrogen dioxide is formed either directly or indirectly when oxygen and nitrogen in the air combine during combustion processes. It is a relatively insoluble gas, which is able to penetrate deep into the lungs, its principal site of toxicity. Its toxicity is thought to be due to its capacity to initiate free radical reactions and to oxidize cellular proteins and other biomolecules (CARB 1992, Appendix A, p. 4).

Sublethal exposures in animals produce inflammation and various degrees of tissue injury characteristic of oxidant damage (Evans in CARB 1992, Appendix A, p. 5). The changes produced by low-level acute or subchronic exposure appear to be reversible when animals are allowed to recover in clean air.

Health effects of particular concern in relation to low-level nitrogen dioxide exposure include: (1) effects of acute exposure on some asthmatics and possibly on some persons with chronic bronchitis, (2) effects on respiratory tract defenses against infection, (3) effects on the immune system, (4) initiation or facilitation of the development of chronic lung disease, and (5) interaction with other pollutants (CARB 1992, Appendix A, p. 5).

Several groups which may be especially susceptible to nitrogen dioxide related health effects have been identified (CARB 1992, Appendix A, p. 3). These include asthmatics, persons with chronic bronchitis, infants and young children, cystic fibrosis and cancer patients, people with immune deficiencies, and the elderly.

Studies using controlled brief exposures on sensitive groups have shown an increase in bronchial reactivity or airway responsiveness of some asthmatics, and decreased lung function in some patients with chronic obstructive lung disease (CARB 1992, Appendix A, p. 2). In general, bronchial hyperreactivity (an exaggerated tendency of the airways to constrict) is markedly greater in asthmatics than in nonasthmatics upon exposure to respiratory irritants (CARB 1992a, p. 107). At exposure concentrations relevant to the current one-hour ambient standard, there appears to be little, if any effect on respiratory symptoms of asthmatics (CARB 1992a, p. 108).

SULFUR DIOXIDE (SO_2)

Sulfur dioxide is formed when any sulfur-containing fuel is burned. SO_2 is highly soluble and consequently absorbed in the moist passages of the upper respiratory system. Exposure to sulfur dioxide can cause changes in lung cell structure and function that adversely affect a major lung defense mechanism known as muco-ciliary transport. This mechanism functions by trapping particles in mucus in the lung and sweeping them out via the cilia (fine hair-like structures) also in the lung. Slowed mucociliary transport is frequently associated with chronic bronchitis.

Exposure to sulfur dioxide can produce both short- and long-term health effects. Therefore, California has established sulfur dioxide standards to reflect both short- and long-term exposure concerns. Based on controlled exposure studies of human volunteers, investigators have found that asthmatics comprise the group most susceptible to adverse health effects from exposure to sulfur dioxide (CARB 1994, p. V-1).

The primary short-term effect is bronchoconstriction, a narrowing of the airways which results in labored breathing, wheezing, and coughing. The short-term (one-hour) standard is based on bronchoconstriction and associated symptoms (such as wheezing and shortness of breath) in asthmatics and is designed to protect against adverse effects from five to ten minute exposures. In the opinion of the California Office of Environmental Health Hazard Assessment, the short-term ambient standard is likely to afford adequate protection to asthmatics engaged in short periods of vigorous activity (CARB 1994, Appendix A, p. 16).

Longer-term exposure is associated with an increased incidence of respiratory symptoms (e.g., coughing and wheezing) or respiratory disease, decreases in pulmonary function, and an increased risk of mortality (CARB 1991a, p. 12). The long-term (24-hour) standard is based upon increased incidence of respiratory disease and excess mortality. The standard includes a margin of safety based on epidemiological studies, which have shown adverse respiratory effects at levels slightly above the standard. Some of the studies indicate a sulfur dioxide threshold for effects, whereby "no adverse effects" are expected from exposures to concentrations at the state standard (Ibid.).

HYDROGEN SULFIDE

Hydrogen sulfide is a naturally occurring colorless, flammable gas that is denser than air. It is typically formed when organic matter undergoes decomposition. Sewer gas, petroleum production and refining and geothermal power plants are identified as specific sources of this gas in California (CARB 1999). When released, the gas tends to be persistent in the atmosphere for about eighteen hours and remains reactive during that time. It has been found to possibly contribute to the formation of sulfur dioxide and sulfuric acid in the atmosphere, thereby resulting in acid rain (ATSDR 1999). Though considered to be very toxic and extremely hazardous, effects triggered by hydrogen sulfide depend basically upon the amount and duration of exposure. Effects resulting from short term relatively high exposures are well documented and are of great concern for occupational safety and health. Consequently, occupational standards are well established for short-term high level exposures to hydrogen sulfide.

The most common cause of sudden death in the workplace is unsafe exposure to high concentrations of the gas (NIOSH 1977). At high concentrations(500-1000 parts per million- ppm), hydrogen sulfide causes unconsciousness and death by respiratory paralysis. At lower concentrations (50-500 ppm), the gas functions as a respiratory irritant, which can lead to pulmonary edema upon exposure to concentrations in excess of 250m ppm. Exposure to concentrations of 20-50 ppm may cause eye irritation and conjunctivitis (ATSDR 1999).

Several studies have examined the impacts of mid to high-level hydrogen sulfide exposure. These studies have reported ocular, respiratory and neurological effects in exposed individuals. The interpretation of the findings of these studies have been impeded by inadequate data for hydrogen sulfide exposure levels, inability to differentiate between effects of high- level acute exposures compared to low-level chronic exposures, concurrent exposures to other organic sulfur compounds, and the subjective nature of some of the health endpoints (ATSDR 1999).

The effects of prolonged low- level exposures to hydrogen sulfide through inhalation of ambient air have not been well studied. In fact, no epidemiological study thus far has demonstrated that prolonged exposures to low doses of hydrogen sulfide has caused adverse health effects.

The U.S. EPA does not presently classify hydrogen sulfide as either a criteria air pollutant or a Hazardous Air Pollutant (CARB 2000). It has however developed a chronic reference concentration of 0.001 milligrams per cubic meter for the gas. The concentration is an estimate of a daily inhalation exposure of the human population including sensitive subgroups that is likely to be without an appreciable risk of deleterious effects during a lifetime. Uncertainty spanning perhaps an order of magnitude is associated with the concentration. California has a statewide ambient air quality standard of 30 parts per billion (ppb) averaged over a period of one hour and not to be equaled or exceeded for the general public. This standard was adopted in 1969, reviewed in 1980 and 1984, and has not changed since no new relevant information has emerged. The California standard is welfare based and intended to protect the public against nuisance odors from hydrogen sulfide (CARB 2000). However, it has been estimated that the 30 ppb threshold would be detectable by about 83 % of the population and would be discomforting to approximately 40% (Amoore 1985). These estimates have been supported by odor complaints and reports of nausea and headache at the 30 ppb exposure level from geyser emissions (Reynolds and Kauper 1984). The odor threshold for hydrogen sulfide that has been reported in literature varies greatly but is generally reported to be less than 10 ppb. Also, effects like headache, nausea, irritability and fatigue may occur with perception of unpleasant odor. The World Health Organization believes that hydrogen sulfide concentrations of 5 ppb averaged over 30 minutes should avoid substantial complaints about odor annoyance among exposed populations (WHO 1981).

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ALTERNATIVES

Testimony of Robert Worl

INTRODUCTION

This section considers potential alternatives to the construction and operation of the proposed Salton Sea Unit 6 (SSU6) geothermal power project. The purpose of this alternatives analysis is to comply with California's environmental laws by providing an analysis of a reasonable range of feasible alternatives that could reduce or avoid any potentially significant adverse impacts of the proposed project (Cal. Code Regs., tit. 14, §15126.6; Cal. Code Regs., tit. 20, §1765). Part 2 of the FSA contains the Air Quality and revised Public Health analyses, which identify significant impacts. In this Alternatives analysis, staff analyzes different technologies and alternative project sites that may reduce or avoid significant impacts. Staff also analyzes the impacts that may be created by locating the project or project elements at alternative sites.

The purpose of staff's alternatives analysis is to provide a reasonable range of feasible alternatives that could substantially reduce or avoid potentially significant adverse impacts of the proposed project. To accomplish this, staff must determine the appropriate scope of analysis. Consequently, it is necessary to identify and determine the potentially significant impacts of the proposed project and then focus on alternatives that are capable of reducing or avoiding the significant impacts of the proposed project. To prepare this alternatives analysis, staff:

- identified the basic objectives of the project, provided an overview of the project, and described its potentially significant adverse impacts;
- identified and evaluated alternative sites (whether the alternative site mitigates the identified impacts of the proposed project and whether the alternative site creates impacts of its own);
- identified and evaluated technology alternatives to the project, including conservation and other renewable sources; and
- evaluated the impacts of not constructing the project, known as the No Project Alternative.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS)

The "Guidelines for Implementation of the California Environmental Quality Act (CEQA)," Title 14, California Code of Regulations section 15126.6(a), provide direction by requiring an evaluation of the comparative merits of "a range of reasonable alternatives to the project, or to the location of the project, which would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project." In addition, the analysis must address the No Project Alternative (Cal. Code Regs., tit. 14, §15126.6(e)).

The range of alternatives is governed by the "rule of reason" which requires consideration only of those alternatives necessary to permit informed decision-making and public participation. CEQA states that an environmental document does not have to consider an alternative if its effect cannot be reasonably ascertained and if its implementation is remote and speculative (Cal. Code Regs., tit. 14, §15125(d)(5)). However, if the range of alternatives is defined too narrowly, the analysis may be inadequate (City of Santee v. County of San Diego (4th Dist. 1989) 214 Cal. App. 3d 1438).

SITE SELECTION AND PROJECT OBJECTIVES

The site selection criteria listed below were used by the applicant for choosing the proposed site. However, staff does not necessarily concur with all the criteria. The project objectives, as determined by staff, are listed in the following section.

According to the Application for Certification (AFC), the applicant chose the proposed site for the following reasons (CEOE, § 3.2.2, pps. 3-3 to 3-5. 2002a):

- the proposed area has proven geothermal reserves;
- the location allows a well field and plant site layout providing the necessary energy production using available acreage, at the closest well spacing possible without undue interference between wells, while sustaining production over the life of the project;
- the location allows taking advantage of the blind fault that bisects the Salton Sea geothermal field, allowing hot brine to be extracted northwest of the fault, while cooled spent brine is reinjected south of the fault without impacting the hotter production zone, and utilizes the minimal spacing between wells supporting the project;
- the location would develop the remaining acreage on the shallow western end of the field that is still on land, between the developed part of the field and the hotter part of the field under the Salton Sea, currently inaccessible but providing pressure support for the developed part of the field;
- the portion of the main blind fault is considered a sealing fault or diffusion boundary preventing temperature interference from the reinjected brine to the production wells;
- the location allows well placement that insures production for the life of the project without interfering with the production at other operating geothermal plants;
- the project would be consistent with the A-3-G (heavy agriculture with a geothermal overlay) existing and planned land uses.
- Based on analysis of the SSU6 AFC, the Energy Commission staff has determined the project's objectives as:
- continued development of the shallow, land-based western zone of the geothermal region currently occupied by power plants;
- generation of approximately 185 MW of load-serving capability in a location with access to Imperial Irrigation Districts (IID) electricity distribution infrastructure;
- location near a water source for use in dilution of reinjected brine;

- capacity to service the 20-year contract with IID for the provision of approximately 170 MW; and
- commercial operation by late 2005.

PROJECT SITE AND POTENTIAL IMPACTS

Staff has determined that hydrogen sulfide (H_2S) and ammonia emissions from the SSU6 will be significant. Emissions of H_2S during plant commissioning are characterized as significant, unmitigable, and temporary. Ammonia is not a regulated criteria pollutant by federal, state or local air quality regulations, but emissions of ammonia would occur during the life of the project, and would likely create significant secondary PM_{10} and $PM_{2.5}$ impacts. Staff and CEOE have investigated potential means of reducing impacts from these emissions (see **AIR QUALITY** section of this FSA for a more complete discussion).

Hydrogen Sulfide (H2S) Emissions

The **AIR QUALITY** section of this FSA identifies significant emissions of H_2S. CEOE has proposed the following project changes which would reduce the operating emissions of H_2S to levels less than significance:

1. reduce the uncontrolled venting of steam;
2. consolidate certain functions and reduce the number of vessels which vent;
3. raise vent stack heights to 80 feet to produce better mixing of emissions.

Commissioning, which is expected to take some 352 hours, approximately 15 days, is expected to cause periodic violations of California Ambient Air Quality Standards (CAAQS) for H_2S when plant emissions combine with high ambient air levels (24 $\mu g/m^3$) in the area. The expected violations are of the one-hour standard of 42 $\mu g/m^3$. This is primarily an odor-based standard but has a health based component as well. The **AIR QUALITY** and **PUBLIC HEALTH** analyses in this FSA indicate that a health-based concern exists based upon short-term effects from detectable odors which may include headaches and nausea for sensitive individuals.

Ammonia (NH_3) Emissions

Ammonia emissions of approximately 2,700 tons per year (tpy) are expected from the project. The ammonia is a non-compressible gas naturally occurring in the brine, which is retained in the steam condensate, and then partitioned at the cooling towers where it is emitted. Though ammonia is a non-regulated emission, it is of concern as it may combine with other air pollutants, notably NO_x, to form fine particulate matter, for which the Imperial Valley is in non-attainment status already. Though this conversion to fine PM is modeled, there is no satisfactory basis for determining the conversion rate, and establishing a range for the potential impacts. Technological means of reducing the ammonia from the condensate stream have been explored by air quality staff and the applicant. (See **AIR QUALITY** section of this FSA).

There are three types of ammonia mitigation explored and potentially available, and each has significant drawbacks which make them infeasible (see **AIR QUALITY** section of the FSA):

1. Chemical regent reduction systems could reduce the ammonia by a variable amount. The initial cost of such a system would be several millions of dollars, with annual supply and maintenance costs adding as much as 39 percent to annual costs.
2. Using recycled water for cooling and reinjecting the steam condensate containing the ammonia would reduce the emissions to minimal levels. Sufficient quantities of recycled water would require developing a collection, treatment, and transportation pipeline from several distant sources to meet the volume requirements for the project. Additional treatment facilities would be required on-site.
3. Dry cooling would require development of additional land, require additions to the parasitic electrical load during summer months. There are technical issues regarding the temperature differentials required for effective cooling of a 200 MW gross power plant using dry cooling.

ANALYSIS OF ALTERNATIVE SITES

The following discussion includes an analysis of two alternative sites. Refer to **ALTERNATIVES Figure 1** for a map showing the location of these sites.

SCREENING CRITERIA USED TO SELECT SITE ALTERNATIVES

The following criteria were used to identify potential alternative sites:

1. the site should avoid or substantially lessen one or more of the potentially significant effects of the project;
2. the site should have access to IID transmission lines accessing key load pockets, preferably through the L-line, and the Midway substation to meet electricity transmission reliability objectives;
3. the site would need sufficient space to construct and operate a geothermal generating facility of this size including a minimum 50-acre parcel of land to accommodate the power plant facilities, approximately 5 acres each for up to eight well pads, appropriate pipeline rights of way; and
4. the site should be within a reasonable distance of reliable sources of geothermal brine, of sufficient volume and temperature, to supply the steam for a project of this size and an available water supply; and
5. the site should have access to appropriate electrical transmission interconnections.

Table 1: COMPARISON OF SITES BASED ON PROJECT IMPACTS

	Site 1 Adjacent Agricultural Land	Site 2 Old Dry Ice/CO_2 Well Site
Air Quality	Same as proposed project	Potential impacts at Niland Closer proximity to residences
Biological Resources	Increased buffer to Yuma clapper rail habitat	May impact waterfowl management areas
Visual Resources	Reduced impacts at KOP-4 sensitive viewing area	Potential impacts not studied
Transmission Interconnection	Same as proposed project	Potential impacts not studied; longer interconnection routes
Noise	Potential reduction of construction and operation noise impact to sensitive species	Potential reduction of construction and operation noise impact to sensitive species
Land Use	Same as proposed project	Site control, similar loss of agricultural lands
Geological Engineering	Same as proposed project	Need for further exploration drilling to delineate geothermal resources

SITE 1 ADJACENT AGRICULTURAL LAND

The adjacent property also owned by the applicant, could hold the proposed project. It is the other half of the 160-acre parcel that would be partially developed by the SSU6 project. This land is appropriately zoned (A-3-G). This location would have similar access to the same geothermal layer proposed for development, would allow for use of the proposed wells, pads and electrical transmission routes, and the same fresh water supply.

In addition this location may be able to reduce the potential noise impact on the Wildlife Refuge-managed lands adjacent to and north of the proposed site, Yuma clapper rail habitat. The Alternate site 1 also may further reduce impacts from project infrastructure to the visual assets seen from the Rock Hill (KOP-4) view site discussed in the Visual Resources section of the FSA.

Location of geothermal plant infrastructure is dependent upon a number of factors, including some sub-surface characteristics not evident from the surface. The current engineering of the site location was done to insure balanced flow of brine from each off the production wells, minimizing the need for mechanical pressure balancing of the brine supply. In addition, for safety reasons, shorter and relatively balanced pipeline segments provide for more safety during planned and emergency shutdowns, protecting both the environment, and the plant equipment. The balancing of the current design can be seen by the location of the wells in relation to the proposed project site. Additionally, the bottom-hole locations of proposed wells are based on detailed geophysical testing and exploratory drilling.

SITE 2 CARBON DIOXIDE (CO_2) WELLS AND DRY ICE PLANT SITE

This site has sufficient undeveloped acreage for the project and is within the Salton Sea Known Geothermal Resource Area. It is approximately three miles west-southwest of the town of Niland, and is between the shore of the Salton Sea and State Highway 111. The site was developed in the 1950's as a dry-ice plant to take advantage of the large CO_2 source discovered during early geothermal exploration in the area. This site has potential advantages that include reduction of noise impacts to the Yuma clapper-rail habitat which is adjacent to the proposed project site, visual impacts at the Sonny Bono Wildlife Refuge (Refuge) areas of Rock Hill (KOP-4) and Red Hill, and air quality impacts from H_2S during commissioning to the Rock Hill and Obsidian Butte. While the site is a greater distance from the Refuge and it is closer to the town of Niland. There may be more residences in the vicinity of Site 2 than at the proposed project site and air quality impacts could occur. Scenic views from the highway and at nearby public recreational areas at the Salton Sea beach line may be negatively affected by a facility at Site 2.

While sufficient undeveloped land is at this site, the ownership of the property needed to insure an appropriate project site is currently not known. Access to water for the project, transmission line rights of way and suitable interconnection sites are also unknown. However, the interconnection routes would be longer than those proposed at the current SSU6 location. Geophysical exploration of the area lags behind that done at the current proposed site, and would not utilize the known resources of the currently developed and explored segment of the KGRA as does the proposed project. Impacts to traffic and transportation may increase as there are fewer access points, and distances to off-site disposal locations for both construction and operational materials are greater. The location is near the Imperial Valley Waterfowl Management Area.

ALTERNATIVE TRANSMISSION LINE ROUTE

Should the BLM choose not to allow the L-Line interconnection to cross the 2.8 mile section of federal lands, the alternative would be a longer route, paralleling State Highway 86 (SH-86) north for approximately 7.5 miles to a point where SH-86 and an IID right-of-way intersects the existing L-Line on non-federal lands. This would avoid the need for the BLM-managed land, and avoid amending the CDCA. Presence of endangered species in the area would necessitate consultation with USFWS through the Endangered Species Act. This route is 4.7 miles longer than the preferred route and it would affect additional private and public property. This may result in increasing economic impacts to the public as Imperial Irrigation District is a publicly-owned utility with operating costs borne through rate structures.

NO PROJECT ALTERNATIVE

The No Project Alternative under CEQA assumes that the SSU6 project is not constructed. In the CEQA analysis, the No Project Alternative is compared to the proposed project and determined to be superior, equivalent, or inferior to it. The CEQA

Guidelines state that "the purpose of describing and analyzing a no project alternative is to allow decision makers to compare the impacts of approving the proposed project with the impacts of not approving the proposed project" (Cal. Code Regs., tit. §15126.6(i)). Toward that end, the No Project analysis considers "existing conditions" and "what would be reasonably expected to occur in the foreseeable future if the project were not approved…" (§15126.6(e)(2)).

If the SSU6 facility were not constructed, the proposed site would continue to be leased for agricultural production. In addition, the site would continue to provide an undeveloped buffer as habitat for birds, and recreational land management of the adjacent Wildlife Refuge.

ALTERNATIVES ELIMINATED FROM DETAILED ANALYSIS

This section describes alternatives that did not satisfy the screening criteria for inclusion in the more detailed analysis presented above. CEQA guidelines state that the alternatives discussion need not consider alternatives that are either infeasible or do not avoid significant environmental impacts. The following were considered as alternatives to the SSU6, but were eliminated from further consideration for the reasons noted.

TECHNOLOGY ALTERNATIVES

Staff considered several alternative generation technologies including a plant that burns fossil fuels. Gas fired, solar, wind, biomass and hydropower are briefly discussed below.

Gas-Fired Power Plant

Most recent power projects are powered by natural gas-fired turbines, with additional power produced by steam turbine generators in combined-cycle plants. It is appropriate to contrast the criteria pollutants emitted by the SSU6 project with characteristics of gas-fired plants of similar capacity. Recent Energy Commission reviews of similar capacity combined-cycle (C-C) gas turbine plants provide a basis for comparison with the SSU6. Table 2 lists the upper limits for emissions from the Pico Power Project, the Walnut Energy Center and Salton Sea Unit 6.

Table 2: Compared Emissions From Gas-Fired Power Projects (Tons/Year)

	NO_x	CO	POC/VOC	PM_{10}*	SO_2	H_2S	NH_3
250 MW C-C[1]	70.2	100	17.4	67	8.7	trace	128.5
147 MW C-C[2]	43	48	11.9	32.8	2.92	trace	73
185 MW SSU6	3.7	10.24	2.24	13.71	.043	21.11	2,754

[1] Walnut Energy Center ; [2] Pico Power Project
* Direct Emission

The comparison above is based upon normal operations, and excludes construction and commissioning emissions, and assumes base-load operation.

Gas-fired plants also require large amounts of water for cooling (1057 acre-feet per year for Pico), while SSU6 uses the steam, recondensed after driving the turbine, as makeup water for the cooling towers. To supplement this source, and to dilute the brine for reinjection, SSU6 may use an additional 293 acre-feet annually. The table above indicates that NOx emissions are higher for gas-fired plants, but these are usually mitigated through emission reduction credits. The Imperial County Air Pollution Control District has indicated that only 10 tons of offsets are available for this purpose.

Conservation and Demand-Side Management

Conservation and demand-side management (DSM) include a variety of approaches, including energy efficiency and conservation, building and appliance standards, load management and fuel substitution. Public Resources Code Section 25305(c) states that conservation, load management, or other demand reducing measures reasonably expected to occur shall be explicitly examined in the Energy Commission's energy forecasts and shall not be considered as alternatives to a proposed facility during the siting process. Since 1975, the displaced peak demand from these efforts has been roughly the equivalent of eighteen 500-MW power plants. At a state level, the annual impact of building and appliance standards has increased steadily, from 600 MW in 1980 to 5,400 MW in 2000, as more new buildings and homes are built under increasingly efficient standards. Savings from energy efficiency programs implemented by utilities and state agencies have also increased (from 750 MW to 3,300 MW). Recent demand reducing proposals from the Governor and Legislature have proven to have an impact by reducing consumption by an average of 3,500 MW during the summer of 2001 (CEC 2001a). In addition, voluntary conservation measures adopted by residential and commercial/industrial users led to a 7.5 percent drop in electricity use throughout the state as of August 2001, but that dropped to 1.5 percent in October 2001 (CEC 2001a). There was a 0.7 percent increase in energy used in February 2002 compared to February 2001 (CEC 2002). However, in comparison to February 2000, there was a 5.5 percent decrease in energy consumption in February 2002 (CEC 2002).

Solar Generation

There are two types of solar generation: solar thermal power and photovoltaic (PV) power generation.

Solar thermal power generation involves the conversion of solar radiation to thermal energy, which is then used to run a conventional steam power system. Solar thermal is a viable alternative to conventional generation systems and, depending on the technology, is suited to either distributed generation on the kilowatt scale or to centralized power generation on scales up to several hundred MW. Solar thermal systems utilize three designs to generate electricity: parabolic trough concentrating collectors, power tower/heliostat configurations, and parabolic dish collectors. Parabolic trough and power tower systems typically run conventional power units, such as steam turbines, while parabolic dish systems power a small engine at the focal point of the collector.

PV power generation involves the direct conversion of light to electricity. PV is best suited to distributed generation uses rather than centralized power generation. PV is the most capital intensive of any alternative generation technology (Aspen 2001). PV power systems consist of solar electric modules (built from PV cells) assembled into arrays of varying sizes to produce electric power proportional to the area of the array and the intensity of the sunlight. PV arrays can be mounted on either the ground or on buildings. They can be installed on dual-purpose structures such as covered parking lots.

Current solar generation technologies require large land areas in order to generate 200 MW of electricity. Specifically, assuming location in an area receiving maximum solar exposure such as desert areas of Imperial County, central receiver solar thermal projects require approximately five acres per MW, so 200 MW would require approximately 1000 acres, or over 10 times the amount of land area taken by the proposed plant site and linear facilities. One square kilometer of PV generation (400 acres) can produce 100 MW of power, so 200 MW would require approximately 800 acres or over 10 times the amount of land area required for the proposed SSU6 project.

Although air emissions are significantly reduced or eliminated for solar facilities, these facilities can have significant visual effects. Solar generation results in the absence or reduction in air pollutant emissions, and visible plumes. Water consumption for solar generation is substantially less than for a geothermal or natural gas fired plant because there is no thermal cooling requirement. In addition, the large avian populations, migratory bird pathways, and relatively large populations of threatened or endangered birds in the Salton Sea area, and Imperial Valley would require careful analysis of habitat reduction or relocation impacts from either solar or PV generation at scale.

Like all technologies generating power for sale into the State's power grid, solar thermal facilities and PV generation require near access to transmission lines. Large solar thermal plants must be located in desert areas with high direct normal insolation, and in these remote areas, transmission availability is limited. Additionally, solar energy technologies cannot provide full-time availability due to the natural intermittent availability of sunlight. Therefore, solar thermal power and photovoltaic power generation would not successfully meet the project objectives of developing 185 MW of load serving electrical generation.

Wind Generation

Wind carries kinetic energy that can be used to spin the blades of a wind turbine rotor and an electrical generator, which then feeds alternating current into the utility grid. Most state-of-the-art wind turbines operating today convert 35 to 40 percent of the wind's kinetic energy into electricity. Modern wind turbines represent viable alternatives to large bulk power fossil power plants as well as small-scale distributed systems. The range of capacity for an individual wind turbine today ranges from 400 watts up to 3.6 MW. California's 1,700 MW of wind power represents 1.5 percent of the state's electrical capacity (Aspen 2001).

Although air emissions are significantly reduced or eliminated for wind facilities, these facilities can have significant visual effects. Wind turbines have also caused bird mortality (especially for raptors) resulting from collision with rotating blades, although this effect is more noted in the Altamont Pass area than in other parts of the state. The large avian populations, migratory bird pathways, and relatively large populations of threatened or endangered birds in the area near the Salton Sea, and Imperial Valley would require careful analysis of utilizing wind resources.

Wind resources require large land areas in order to generate 200 MW of electricity. Depending on the size of the wind turbines, wind generation "farms" generally can require between five and 17 acres to generate one megawatt (CEC 2001b). A 200 MW project would therefore require between 1,000 and 3,400 acres. Although 7,000 MW of new power wind capacity could cost-effectively be added to California's power supply, the lack of available transmission access is an important barrier to wind power development (Beck et al. 2001). California has a diversity of existing and potential wind resource regions that are near load centers such as San Francisco, Los Angeles, San Diego and Sacramento (CEC 2001c). However, wind energy technologies cannot provide full-time availability due to the natural intermittent availability of wind resources. Therefore, wind generation technology would not meet the project's goal, which is to provide load-serving capacity.

Biomass Generation

Biomass generation uses a waste vegetation fuel source such as wood chips (the preferred source) or agricultural waste. The fuel is burned to generate steam. Biomass facilities generate substantially greater quantities of air pollutant emissions than geothermal or natural gas burning facilities. In addition, biomass plants are typically sized to generate less than 20 MW, which is substantially less than the 200 MW gross output of the SSU6 project. At the peak of the biomass industry, 66 biomass plants were in operation in California, but as of 2001, only about 30 direct-combustion biomass facilities were in operation (CEC 2001d).

In order to generate 200 MW, ten 20 MW biomass facilities would be required. These power plants would have air quality and waste management impacts of their own.

Hydropower

While hydropower does not require burning fossil fuels and may be available in California, this power source can cause significant environmental impacts, due primarily to the inundation of many acres of potentially valuable habitat and the interference with fish movements during their life cycles. In addition, planning and permitting time is on the order of 10 years for a hydropower facility. As a result, it is extremely unlikely that new large hydropower facilities could be developed and permitted in California within the next several years (Aspen 2001). Though IID currently owns 85 MW of hydroelectric generation capacity, it does not seem practical to expand that capacity by 185 MW in the near term.

Cost Comparisons of Electricity Generation Technologies

Cost comparisons using direct levelized cost across varied technologies have been published as part of the California Energy Commission's Integrated Energy Policy Report (Appendix B, IEPR, June 5, 2003). It is useful to consider these costs when comparing technological approaches diversifying sources of power generation. Factors such as operational mode, size of output, availability, and capacity are often a function of developing markets, technological advances, and energy source or fuel. The following information is an abbreviated table drawn from the IEPR Appendix B:

Table 3: Technology Costs*

Type of Facility	Fuel Source	Operating Mode	Gross Capacity (MW)	Direct Cost Levelized (cents/kWh)
Combined Cycle	Natural Gas	Baseload	500	5.18
Wind	Wind	Intermittent	100	4.93
Hydropower	Water	Load-Following, Peaking	100	6.04
Solar-Parabolic Trough	Sun	Load-Following	110	21.53
Geothermal-Flash	Geothermal Water	Baseload	50	4.52

* From: California Energy Commission Integrated Energy Report, *Comparative Cost of California Central Station Electricity Generation Technologies Report, Appendix B*, June 5, 2003.

Conclusion Regarding Alternative Technologies

Alternative generation typically has specific resource needs, environmental impacts, permitting difficulties, and intermittent availability. Therefore, these technologies do not fulfill a basic objective of the proposed project to provide baseload operation and load-serving capability in order to ensure a reliable supply of electricity for Imperial Irrigation District customers and California. With the exception of a natural gas-fired plant none can operate as a baseload facility. Consequently, staff does not believe that these alternate technologies present feasible alternatives to the proposed project.

EMISSION REDUCTION TECHNOLOGIES

There are no technically or cost-effective means of eliminating the short-term impacts that may arise during the 15-day commissioning period. These emission impacts are short term impacts to a CAAQS standard primarily based upon detectable odor.

Ammonia emission reduction has been explored (see **AIR QUALITY**). It is difficult to determine an accurate conversion rate to PM_{10}, clarifying the secondary impact of the ammonia emissions from SSU6. Available means of reducing the ammonia emitted are not highly effective, and are currently cost or availability prohibitive.

CONCLUSIONS

Staff does not consider alternative technologies (solar, wind, biomass, and hydroelectric) to be feasible alternatives to the proposed project. While the No Project Alternative would eliminate all impacts of this project, the objectives of further development of the Salton Sea KGRA, increasing in-state generation, adding capacity within Imperial County and expanding the state-wide renewables portfolio, would not be achieved. This may result in environmental impacts being shifted to other power plant locations within the state, or across the nearby border with Mexico.

The two site alternatives and the transmission line alternative considered in this section offer a few advantages and several disadvantages in comparison to the proposed project location. Similar to the proposed project, both of the alternative sites would have the potential to cause potentially significant air quality, biological, noise, land use and linear facility impacts. Therefore, no alternative site is recommended over the proposed project.

The emissions reduction options available to reduce impacts from H_2S and ammonia have either been effectively applied, or are not currently practical from the stand point of cost, technical effectiveness, or availability.

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_____ 2003. Personal Communication. Bernard Raemy to Robert Worl. January 14, 2003.

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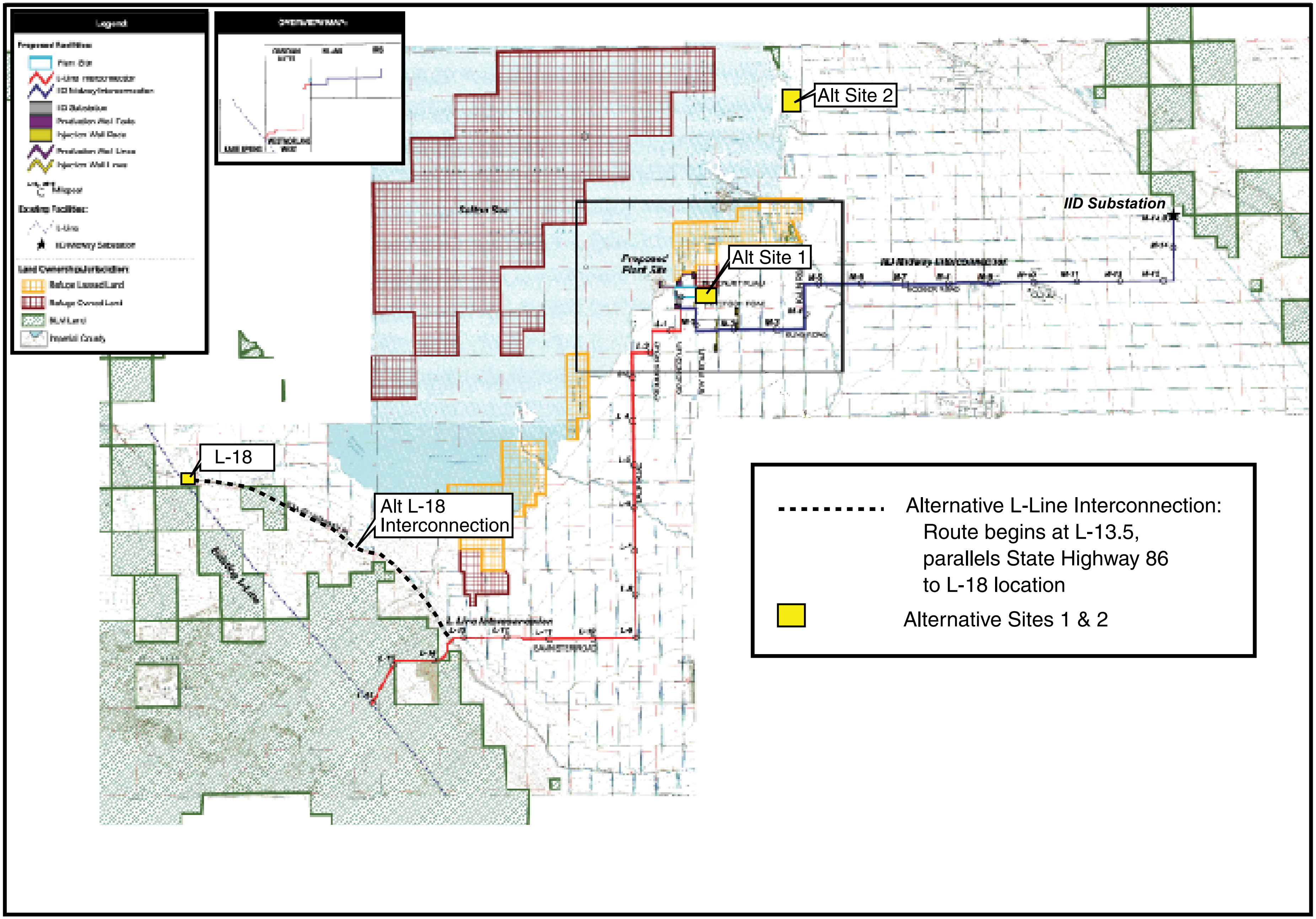
ALTERNATIVES - FIGURE 1

Salton Sea Geothermal Unit #6 Power Project - Alternatives 1 & 2, and L-line interconnection



CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, SEPTEMBER 2003

SOURCE: AFC Figure 5.8-1A

SALTON SEA UNIT 6 PROJECT
FSA (PART 2) PREPARATION TEAM

Executive Summary ....Robert Worl

Air Quality ....Lisa Blewitt and William Walters

Public Health..Ramesh Sundareswaran

Alternatives ....Robert Worl

Project Assistant ....Angela Hockaday

Support Staff .... Keith A. Muntz

DECLARATIONS
AND
RESUMES

DECLARATION OF
Lisa A. Blewitt

I, **Lisa Blewitt** declare as follows:

1. I am presently employed by Aspen Environmental Group, a contractor to the California Energy Commission, in the Agoura Hills office as an associate in engineering and physical sciences.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I helped prepare the staff testimony on **AIR QUALITY** for the **SALTON SEA UNIT #6 PROJECT** based on my independent analysis of the Application for Certification and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 9/25/2003 Signed: Lisa Blewitt

At: Agoura Hills, California

LISA A. BLEWITT
Associate Engineer/Physical Scientist

ACADEMIC BACKGROUND
B.S., Chemical Engineering, University of California, Santa Barbara, 1996

PROFESSIONAL EXPERIENCE

Miss Blewitt is a chemical engineer with experience in air, plume and noise analysis. Prior experience includes refinery and power plant design. Project management experience includes helping manage the Aspen team (Aspen employees plus all subcontractors) for several California Energy Commission (CEC) projects, and support on various proposals.

Aspen Environmental Group **August 2001 to present**

Miss Blewitt's project experience at Aspen includes the following:

California Energy Commission (CEC): Miss Blewitt performed plume analysis and/or air quality analysis on several projects to support the Staff Assessments for the CEC's CEQA equivalent review process. She helps manage the Aspen team as Power Plant Coordinator (PPC). Coordination of the Aspen team with CEC project managers includes providing up-to-date information to all members of the team, identifying key issues, and preparing monthly progress reports. She also manages the Aspen team as the overall Aspen PPC for all CEC projects by providing weekly progress reports to all Aspen PPC's.

- **Avenal:** AFC for 600 MW combined cycle plant located in Avenal, Kings County. Miss Blewitt performed the plume analysis for the cooling tower, heat recovery steam generators (HRSGs), and auxiliary boiler.
- **Blythe 2:** Aspen Team Power Plant Coordinator to support the Staff Assessment of the AFC for a 520 MW combined cycle power plant located entirely within the previously approved Blythe Energy Project facility boundaries west of the City of Blythe, Riverside County. Miss Blewitt will be performing the plume analysis. She also performed a cooling tower plume ground level fogging analysis to determine impacts to surrounding roadways.
- **Central Valley Energy Center:** Aspen Team Power Plant Coordinator to support the Staff Assessment of the AFC for a 1,060 MW combined cycle power generation facility located in the City of San Joaquin, Fresno County. Miss Blewitt assisted with the air quality analysis, and performed the plume analysis for the cooling tower, HRSGs, and auxiliary boiler. She also performed a cooling tower plume ground level fogging analysis to determine impacts to surrounding roadways.
- **Colusa CC:** AFC for a 500 MW combined cycle power generation facility located west of the City of Williams in Colusa County. Miss Blewitt assisted with the air quality analysis.
- **East Altamont:** AFC for a 1,100 MW combined cycle power generation facility located southeast of Tracy in Alameda County. Miss Blewitt assisted with the cooling tower plume analysis. She also performed a cooling tower plume ground level fogging analysis to determine impacts to surrounding roadways.

- **Henrietta:** AFC for a 91.4 MW simple cycle power plant to be located west of the City of Lemoore, in Kings County. Miss Blewitt assisted with the air quality analysis and performed the plume analysis for the HRSGs. This plant did not require a cooling tower.
- **Inland Empire:** AFC for a 670 MW combined cycle power plant to be located near the town of Romoland and Perris, within an unincorporated area of Riverside County. Miss Blewitt performed the plume analysis for the cooling tower, HRSGs, and auxiliary boiler.
- **Los Esteros Critical Energy Facility:** Aspen Team Power Plant Coordinator to support the Staff Assessment of the AFC for a 180 MW simple cycle peaking plant in San Jose, CA.
- **Magnolia:** AFC to add 250 MW of new generation at Magnolia Generation Power Plant in Burbank, CA. Miss Blewitt assisted in the air quality analysis and performed the plume analysis for the cooling tower and HRSGs. She also performed a cooling tower plume ground level fogging analysis to determine impacts to surrounding roadways.
- **Roseville Energy Facility:** AFC for 900 MW combined cycle power plant five miles northwest of downtown Roseville in Placer County. Miss Blewitt performed the plume analysis for the cooling towers.
- **SMUD Consumnes:** AFC for 1000 MW combined cycle power plant to be located at the Rancho Seco Nuclear Power Plant in Sacramento County. Miss Blewitt performed the plume analysis for the cooling towers and HRSGs.
- **South Star:** AFC for 100 MW simple cycle power plant (SS I) located in the Texaco South Midway-Sunset Oilfield, Kern County. Miss Blewitt assisted with the air quality analysis. Project cancelled.
- **Spartan:** Power Plant Coordinator for Aspen team to support the Staff Assessment of the AFC for a 96 MW simple cycle peaking plant in San Jose, CA. Project cancelled.
- **Tracy:** Aspen Team Power Plant Coordinator to support the Staff Assessment of the AFC for a 169 MW simple cycle power plant to be located southwest of the City of Tracy, in western San Joaquin County. Miss Blewitt also assisted with the air quality analysis and performed the plume analysis based on results from Spartan I Energy Center Project.
- **Vernon:** AFC for the Malburg Generating Station (MGS), a 120 MW combined cycle power plant to be located in the City of Vernon, Los Angeles County. Miss Blewitt performed the plume analysis for the cooling tower and HRSGs. She also performed a cooling tower plume ground level fogging analysis to determine impacts to surrounding roadways.

Los Angeles Unified School District (LAUSD): Miss Blewitt performed noise analysis and/or parking studies for the following projects.

- **Wonderland:** Three-story stick building classroom addition to an existing elementary school. Miss Blewitt attended a site visit to analyze the current project alternatives and provided an update to the project manager regarding the impact to issues previously identified for the original configuration. Miss Blewitt performed the noise analysis for the proposed project in October 2002.
- **Narbonne:** Portable additions to an existing high school. Miss Blewitt performed a parking study to determine baseline parking conditions prior to addition of new portables.
- **Wilson:** Portable additions to an existing high school. Miss Blewitt performed a parking study to determine baseline parking conditions prior to addition of new portables.

- **Reseda:** Portable additions to an existing high school. Miss Blewitt performed a noise analysis in October 2002 to determine the significance of noise impacts due to the addition of fifteen classroom buildings and two sanitary buildings on the existing school campus. Coordinated with staff to incorporate all District comments into the Initial Study, and prepared the draft Mitigated Negative Declaration.

Proposals: Miss Blewitt assisted in the development of the following proposals:

- **Department of Water and Power On-Call:** Miss Blewitt coordinated the subcontractors including collecting all resumes, project descriptions, firm descriptions, and references.
- **Miguel Mission:** Miss Blewitt coordinated the subcontractors including collecting all letters of participation, conflict of interest statements, disclosure tables, resumes, project descriptions, technical approaches, and references.

Fluor Daniel, Inc. **August 1996 to July 2001**

Miss Blewitt was a Process Engineer at Fluor Daniel, Inc. in Aliso Viejo, CA from August 1996 to July 2001. She did process design work for both refineries and power plants.

- **Occidental Chemical Taft Cogeneration Project:** Worked with Duke Fluor Daniel to independently develop the design of multiple process systems including wastewater treatment, storm water, potable water, hydrogen and natural gas. Coordinated and discussed design issues with civil/structural, architectural, piping, mechanical, project engineers and the client to develop and optimized, cost-effective design. Developed process flow diagrams (PFD) and piping and instrument diagrams (P&ID) to meet all safety and operability requirements set by the client and industry standards. Confirmed piping layouts met system hydraulic requirements for proper operation considering design and alternate operating cases.
- **Georgia-Pacific Steam Reformer Project:** Lead flue gas recycle study to determine operating requirements for combustion in pulse heaters.
- **Syncrude Canada Upgrader Expansion (UE-1) Project:** Prepared the Design Basis Specification and defined the revamp modifications required to debottleneck a Naphtha Hydrotreater Plant. Conducted the PFD Review for design approval with the client in Fort McMurray, Alberta, Canada. Simulated the Naphtha Hydrotreater Plant. Completed multiple configuration studies to determine the best configuration for UE-1.

ADDITIONAL TRAINING AND COURSES:
Engineer-In-Training Certificate
UCSB Extension 2-day class - Preparing CEQA/NEPA Documents
UCSB Extension Project Management Professional Certification Program (9/02 - 06/03) – 16 units total

PROFESSIONAL AFFILIATIONS: UCSB Alumni Association

DECLARATION OF
William D. Walters

I, **William Walters** declare as follows:

1. I am presently employed by Aspen Environmental Group, a contractor to the California Energy Commission, in the Agoura Hills office as a senior associate in engineering and physical sciences.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I helped prepare the staff testimony on **AIR QUALITY** for the **SALTON SEA UNIT #6 PROJECT** based on my independent analysis of the Application for Certification and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: September 24, 2003 Signed: ____________

At: Agoura Hills, California

William Walters, P.E.
Air Quality Specialist

Academic Background

B.S., Chemical Engineering, 1985, Cornell University

Professional Experience

Mr. Walters has over sixteen years of technical and project management experience in environmental compliance work, including environmental impact reports, RCRA/CERCLA site assessment and closure, site inspection, source monitoring, emissions inventories, source permitting, and energy and pollution control research.

Aspen Environmental Group **2000 to Present**

Responsible as lead technical and/or project manager of environmental projects. Specific responsibilities and projects include the following:

- Preparation and/or project management of the air quality section of the Staff Assessment and/or Initial Study for the following California Energy Commission (CEC) licensing projects.
  - Hanford Energy Park.
  - United Golden Gate, Phase 1
  - Huntington Beach Modernization Project (including Expert Witness Testimony)
  - Woodland Generating Station 2
  - Ocotillo Energy Project, Phase 1
  - Magnolia Power Project
  - Colusa Power Project
  - Henrietta Peaker Project
  - Tracy Peaking Power Plant Project
  - San Joaquin Valley Energy Center
- Assistance in the preparation of the noise assessment section of the Staff Assessment for the Contra Costa Power Plant CEC licensing project
- Preparation of the staff paper "Emission Offsets Availability Issues", and preparation of the Emission Offsets Constraints Workshop Summary paper for the CEC.
- Preparation and project management of the public health section of the Initial Study for the Woodland Generating Station 2 CEC licensing project.
- Issue area coordinator providing support for the air quality analyses and/or visual plume assessments for the Inland Empire Energy Center, Los Esteros Critical Energy Facility, Palomar Energy Project, Avenal Energy Project, and the Tesla Power Plant Project

- Preparation and/or project management of the visual plume assessment for the following California Energy Commission (CEC) licensing projects:
  - Metcalf Energy Center Power Project (including Expert Witness Testimony)
  - Contra Costa Power Plant Project (including Expert Witness Testimony)
  - Mountainview Power Project
  - Potrero Power Plant Project
  - El Segundo Modernization Project
  - Magnolia Power Project
  - Morro Bay Power Plant Project
  - Valero Cogeneration Project
  - East Altamont Energy Center (including Expert Witness Testimony)
  - Russell City Energy Center
  - SMUD Cosumnes Power Plant Project
  - City of Vernon Malburg Combined Cycle Plant
  - Inland Empire Energy Center
  - Palomar Energy Project
  - San Joaquin Valley Energy Center
  - Woodland Generating Station 2
  - Hanford Energy Park
  - United Golden Gate, Phase I
  - Huntington Beach Modernization Project
  - Ocotillo Energy Project, Phase I
  - Colusa Power Project
  - Henrietta Peaker Project
  - Tracy Peaking Power Plant Project
  - Avenal Energy Project

- Preparation of the air quality section of the PG&E Hydrodivestiture Draft EIR/EIS for the California Public Utilities Commission (CPUC).

- Emission inventory for the construction activities forecast for the San Jose/Old San Jose Creeks Ecosystem Restoration project for the United States Army Corps of Engineers (USACE).

- Preparation of emission inventory and Conformity Analysis of the Murrieta Creek Flood Control Project for the USACE.

- Preparation of permit applications, emission calculation spreadsheets, and an air quality compliance manual for Desa International's Southern California manufacturing facility.

Camp Dresser & McKee, Inc. **1998 to 2000**

Mr. Walters was responsible as lead technical and/or project manager of environmental projects. Specific responsibilities and projects include the following:

- Preparation of emission inventories and dispersion modeling for criteria and air toxic pollutants for the Los Angeles International Airport Master Plan (LAXMP) EIS/EIR.

- Project manager/technical lead for the completion of Risk Management Plans (RMPs) for four J.R. Simplot food processing facilities in Oregon, Idaho and Washington and the Consolidated Reprographics facility located in Irvine, California. Project manager for the concurrent Process Safety Management plan support for the J.R. Simplot Hermiston Oregon and Heyburn Idaho facilities and the project manager/technical lead for the RMP support for the SSI food processing facility in Wilder, Idaho and the Atlantic Custom Processors food processing facility in Fort Fairfield, Maine.

- Project Manager/Technical lead for the completion of air permit applications and air compliance audits for two Desa International fireplace accessory manufacturing facilities located in Santa Ana, California.

- Air quality audit for a confidential can manufacturing company at two manufacturing sites.

- Completion of an environmental tax credit application for the J.R. Simplot Hermiston Oregon food products facility.

Planning Consultants Research **1997 to 1998**

Mr. Walters was responsible as lead technical and/or project manager of environmental projects. Specific responsibilities and projects include the following:

- Project Manager for a stationary source emission audit of the entire Los Angeles International Airport complex for Los Angeles World Airports (LAWA) in support of the LAXMP.

- Review of the Emission Dispersion Modeling System (EDMS) and preparation of a report with findings to the Federal Aviation Administration for LAWA in support of the LAXMP.

- Project manager for the ambient air monitoring and deposition monitoring studies performed for LAWA in support of the LAXMP, including the selection of the monitoring sites and specialty subcontractor, and review of all monitoring data.

- Completion of intersection "CO Hotspots" modeling, ambient monitoring, and deposition monitoring reports for LAWA in support of the LAXMP.

Aspen Environmental Group/Clean Air Solutions **1995 to 1996**

Mr. Walters was responsible as lead technical and/or project manager of environmental projects. Specific responsibilities and projects include the following:

- Manager of the Portland, Oregon, office of Clean Air Solutions from March 1995 to December 1995, with responsibilities including Project Management, Business Development, and Administration.

- Control technology assessment, engineering support and Notice of Intent to construct preparation for J.R. Simplot's Hermiston, Oregon food processing facility.

- Air quality compliance report including an air emission inventory, regulation and permit compliance determination, and recommendations for compliance for Lumber Tech, Inc.'s Lebanon, Oregon wood products facility.

- Review and revision of an Air Contaminant Discharge Permit application, Title V permit application, and PSD modeling analysis for J.R. Simplot's Hermiston, Oregon food processing facility.

- Source test methodology and equipment selection for testing inlet and outlet concentrations of total petroleum hydrocarbon and benzene from soil gas extraction/oxidation units for Cascade Earth Sciences, Ltd.

- Preparation of a Tier II (synthetic minor) permit application for the American Fine Foods' Payette, Idaho food processing facility.

DECLARATION OF
Robert Worl

I, **Robert Worl**

1. I am presently employed by the California Energy Commission in the **Environmental Office** of the Systems Assessments and Facilities Siting as a Planner II, Project Manager.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I helped prepare the staff testimony on **Alternatives**, for the **Salton Sea Unit 6 Project** based on my independent analysis of the Application for Certification and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

   I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 26 September 2003 Signed: Robert Worl

At: Sacramento, California

Robert Worl, Planner II

EDUCATION AND ADDITIONAL INFORMATION

BA degree, Central Washington State College
2 years graduate study, University of Alaska-Anchorage
Additional Courses: Advanced Land Use Planning and Administration, Hazardous Waste Operation and Emergency Response (HAZWOPR) Confined Space, H2S, CPR and First Aid

Project Manager-Planner II, California Energy Commission, May 1, 2001 – Present
Currently engaged as a Project Manager coordinating a team of resource specialists evaluating Applications for Certification (AFC's) submitted by power plant developers under Energy Commission guidelines. Work involves coordination of evaluation and research efforts by applicants, staff, consultants, state, federal and local jurisdictions. Work follows the Energy .

Training Coordinator, Operator IV, Solid Waste Technician II
North Slope Borough and Piqunig Management Corp. (PMC) 1980-2000
First built and operated by the North Slope Borough (NSB) in 1979, and contracted to PMC in 1994, the facilities provided solid waste, landfill, water/wastewater and oily waste collection, treatment and disposal for the Prudhoe Bay oil field. Established training programs, and assisted in development of hiring and personnel policies/practices, and provided support to management during construction and commissioning of an industrial incineration system:

Research and Organization Consultant, Robert Worl Associates 1989-1995
Consultant to municipal and non-profit organizations. Primary focus was rural Alaska, Board/Management workshops, strategic planning, and staff coaching. Additionally assisted with project development, grant writing and negotiations with state and federal sources.

Research Associate, Professional Growth Systems, Inc. (PGS) 1987-1989
PGS is a consulting firm specializing in strategic planning, board and management organization.

NPR-A Coordinator, North Slope Borough 1977-1978
Represent local interests on a Federal State Local Government Task Force developing a long-range use plan for the newly created National Petroleum Reserve-Alaska. Edited and wrote portions of "Native Livelihood and Dependence" Task Force Report. Prepared and conducted the Public Participation Plan, assisted with agency and Congressional staff briefings,

Director, Health and Social Services Department, North Slope Borough 1975-1977
Research, program planning, manage contracts with Federal and State agencies.

PUBLICATIONS:

Beaufort Sea Sociocultural Systems Update Analysis. Worl, Robert, Worl, Rosita, and Lonner, Thomas. Alaska OCS Socioeconomic Studies Program, Technical Report No. 64. Anchorage. 1981

Beaufort Sea Sociocultural Systems. Worl Associates (Robert and Rosita Worl). Alaska OCS Socioeconomic Studies Program, Technical Report No. 9. Anchorage: Mineral Management Service (formerly Bureau of Land Management) 1978.

Native Livelihood and Dependence. Worl, Robert (Contributor and Editor), National Petroleum Reserve-Alaska, Land Use Study, Anchorage: Bureau of Land Management. 1978.